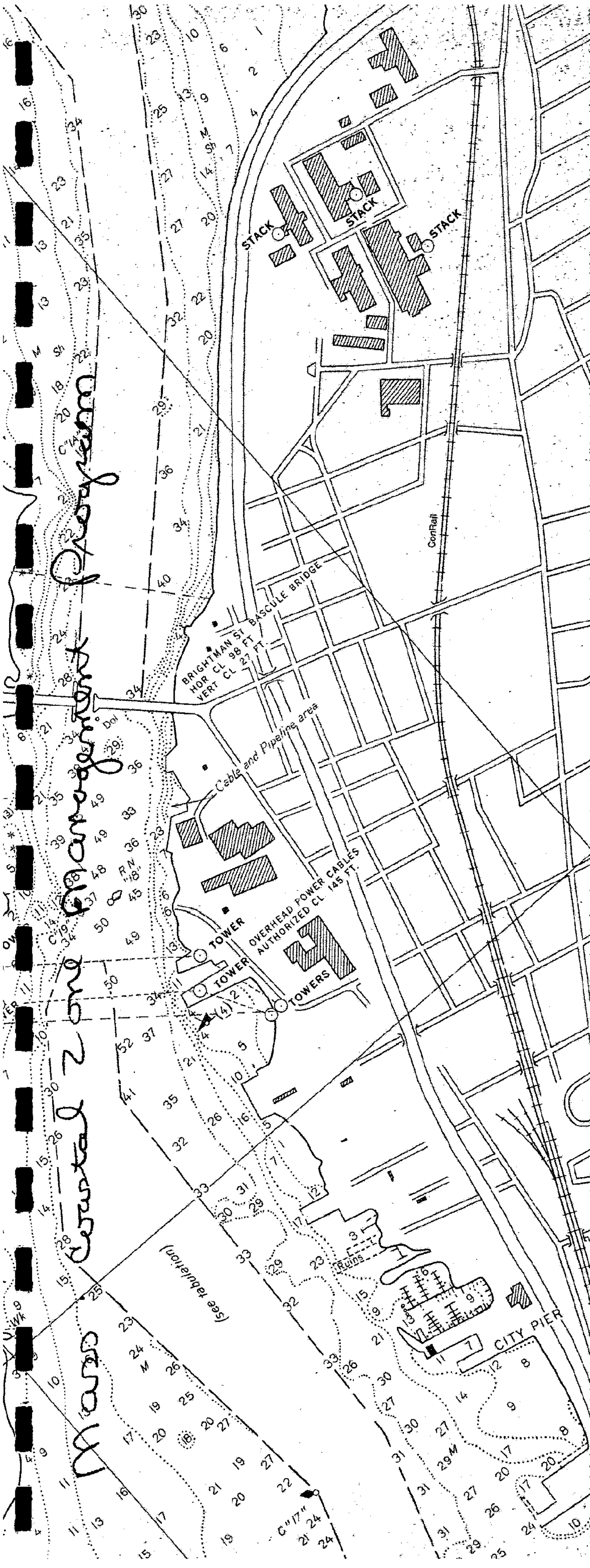

WATERFRONT STUDY

A07-4

City of Fall River, Massachusetts

MASSACHUSETTS COASTAL ZONE MANAGEMENT OFFICE

COASTAL ENERGY IMPACT PROGRAM

February, 1981

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I. INTRODUCTION

A. Background

At a recent seminar on the impact of offshore oil and gas on adjacent coastal areas, W.D.C. Lyddou, Chief Planning Officer for the Scottish Development Department, delivered a presentation entitled "Planning Aspects of Oil Related Development", based on his experience with development of North Sea resources. The presentation focused on three distinct points:

- the atmosphere of uncertainty surrounding offshore oil and gas activities demands more, not less, planning;
- such planning should be comprehensive, not just limited to impact analysis;
- the mystique surrounding oil and gas development obscures the fact that what is required is simply good industrial planning, both long- and short-term, area-wide and site specific.

Had Scotland not anticipated, planned, and prepared for the influx of activity due to development of North Sea resources, outside forces could have determined the rate and direction of growth and controlled land use planning.

In order to reduce dependence on foreign energy supplies, the United States is currently proceeding with a program of leasing offshore tracts believed to contain economically recoverable reservoirs of oil and/or gas. General locations of Outer Continental Shelf (OCS) lease areas are shown in Figure 1. The east coast of the U.S. has been divided into three OCS regions, covering the South, North, and Mid-Atlantic areas. Thus far, one lease sale each has been held in the North and South Atlantic Regions (Lease Sale Numbers 42 and 43, respectively), and two sales (Lease Sale Numbers 40 and 49) have been held in the Mid-Atlantic. Figure 2 shows the location of these lease areas. Figure 3 shows the location of tracts leased thus far in the North and Mid-Atlantic, as well as those proposed for Lease Sale Number 59, the next sale scheduled for the Mid-Atlantic.

Exploratory drilling in the South and Mid-Atlantic Regions have not produced any commercially exploitable finds to date. Drilling has not yet begun in the North Atlantic, but the permit process has been initiated and drilling is expected to begin in 1981. Future lease sales in the North and Mid-Atlantic are scheduled as follows:

Sale No. 59, Mid-Atlantic, December 1981
Sale No. 52, North Atlantic, October, 1982
Sale No. 76, Mid-Atlantic, November, 1983
Sale No. 82, North Atlantic, October, 1984

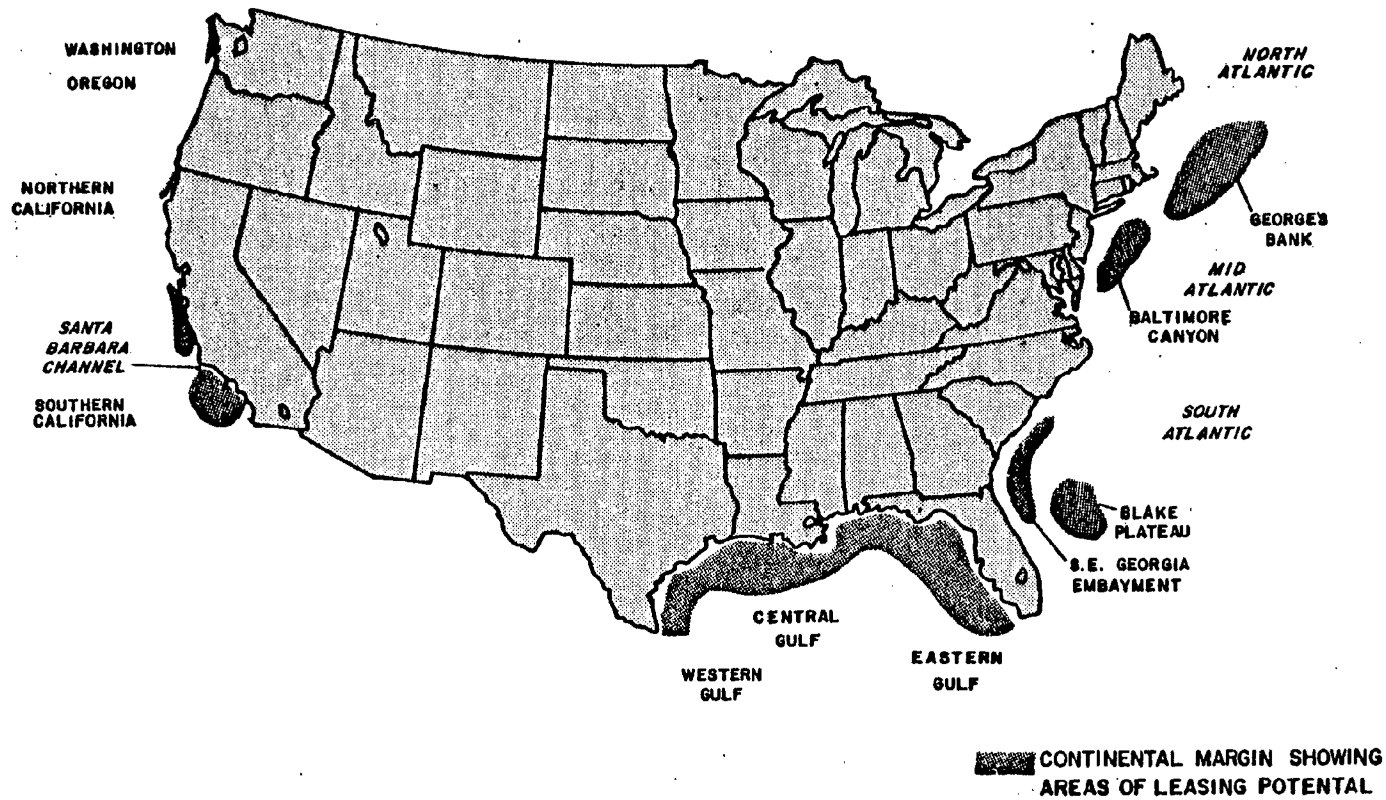

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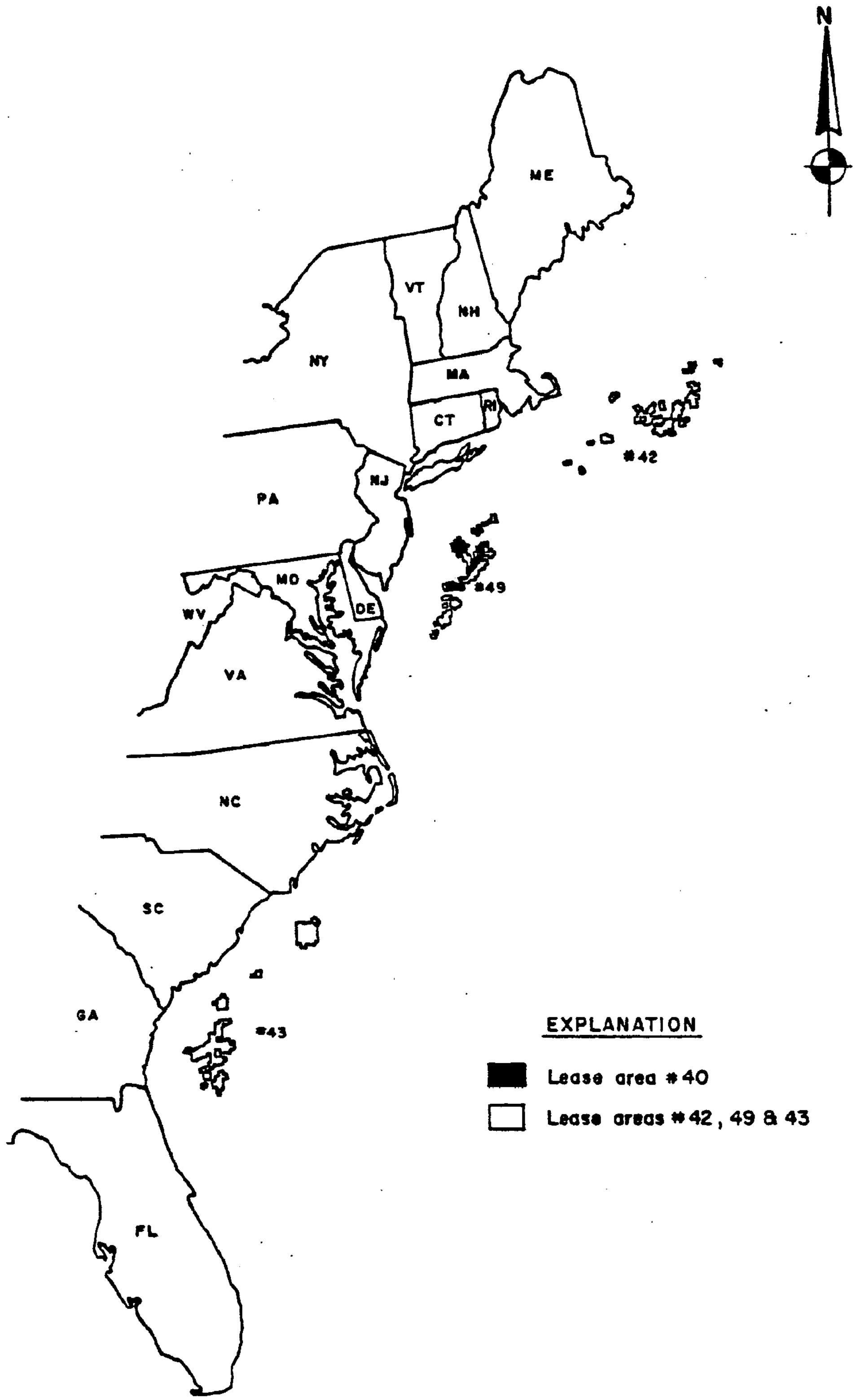
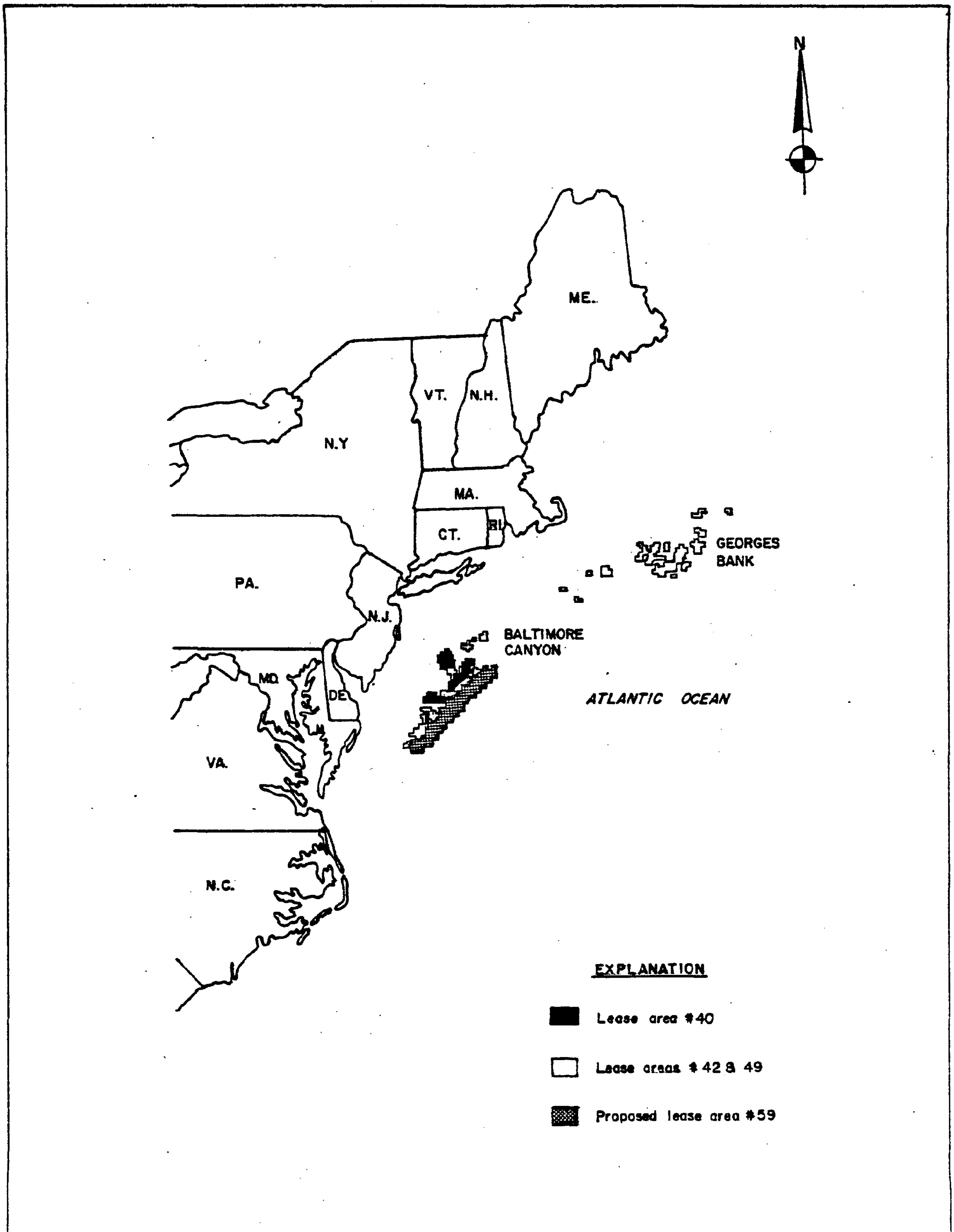
FIG NO. 1



MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB. 1981	FIG NO. 2



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B. Purpose

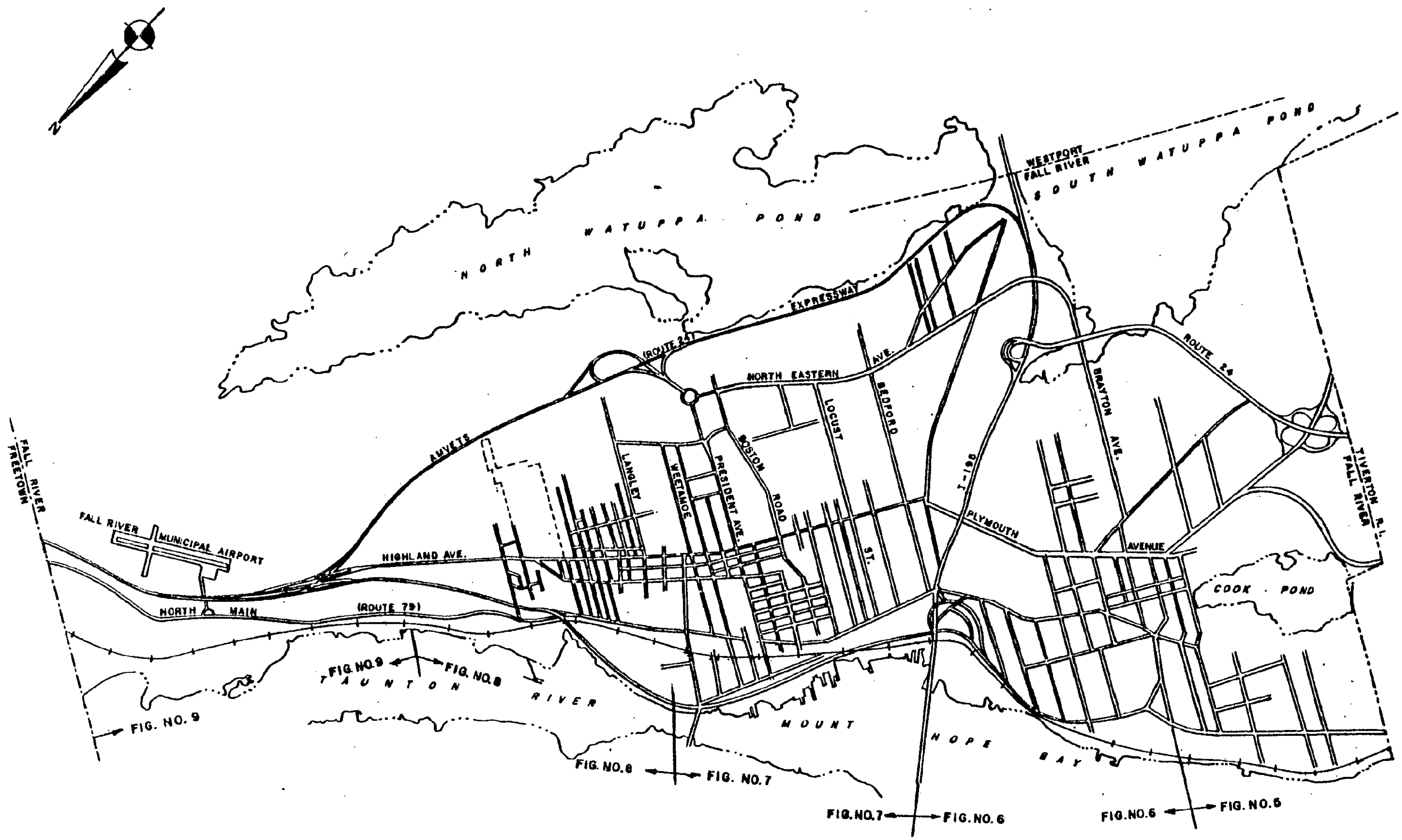
As a result of its location in relation to present and future offshore oil and gas activities on Georges Bank and the Baltimore Canyon, the City of Fall River is a potential site for onshore support facilities. The Port of Davisville, also located in Narragansett Bay, is currently the site of operations supporting offshore activities on the Baltimore Canyon, and activity in both offshore regions is expected to increase considerably over the next few years, as a result of scheduled lease sales. The purpose of this study is to identify impacts on environmental and recreational resources in Fall River due to offshore oil and gas activities and develop specific strategies to mitigate those impacts.

In Chapter II the Fall River shoreline is inventoried, identifying land use patterns, environmentally sensitive and recreational areas and areas of potential development. Offshore and onshore activities related to outer continental shelf operations are described in Chapter III, with impacts and requirements of onshore support facilities listed in table form. Chapter IV presents an assumed scenario of OCS development in the North and Mid-Atlantic Regions and resultant support facility requirements and siting considerations. This scenario is explained in more detail in Appendix A. Chapter V identifies specific potential uses and impacts of the development sites presented in Chapter II and describes strategies and measures to mitigate adverse impacts.

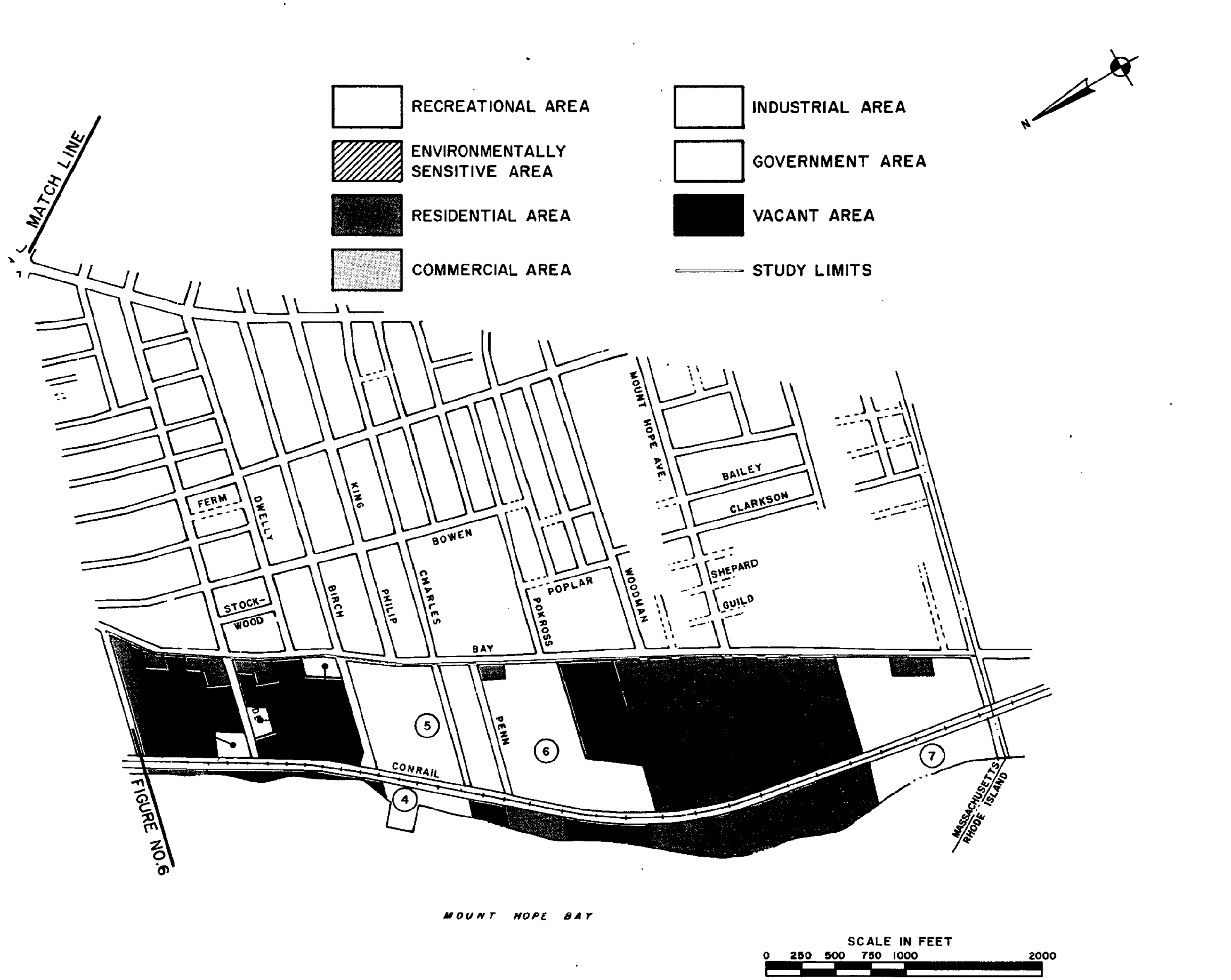
II. SHORELINE INVENTORY

The City of Fall River has approximately 10.5 miles of shoreline, running in a generally northeasterly direction from its southern boundary with the Town of Tiverton, Rhode Island, to its northern boundary with the Town of Freetown, Massachusetts. There are three general areas of the waterfront in terms of topography. The southern portion, commonly referred to as the Bayside area, is characterized by a small cliff-like formation rising approximately 15 feet above sea level. The central portion, consisting primarily of the commercial/industrial area, is generally flat. The northern portion continues to be relatively flat until just past the Shell Oil Company terminal, where it rises rather sharply from the water's edge to form the side of a large hill.

For the purposes of this study, the shoreline has been divided into five sections. Figure 4 shows the entire waterfront, as well as the boundaries defining the limits of the five sections. Figures 5 through 9 show land use patterns along the shoreline, beginning at the southern border and proceeding north. The areas of potential waterfront development included in this study have been assumed to extend from the water's edge back to the first major road or street. This limit is generally Bay Street in the southern portion of the waterfront, the Western Expressway in the central portion, and North Main Street in the northern portion. A previous inventory of the Fall River shoreline used the railroad tracks and right-of-way as the shoreline study

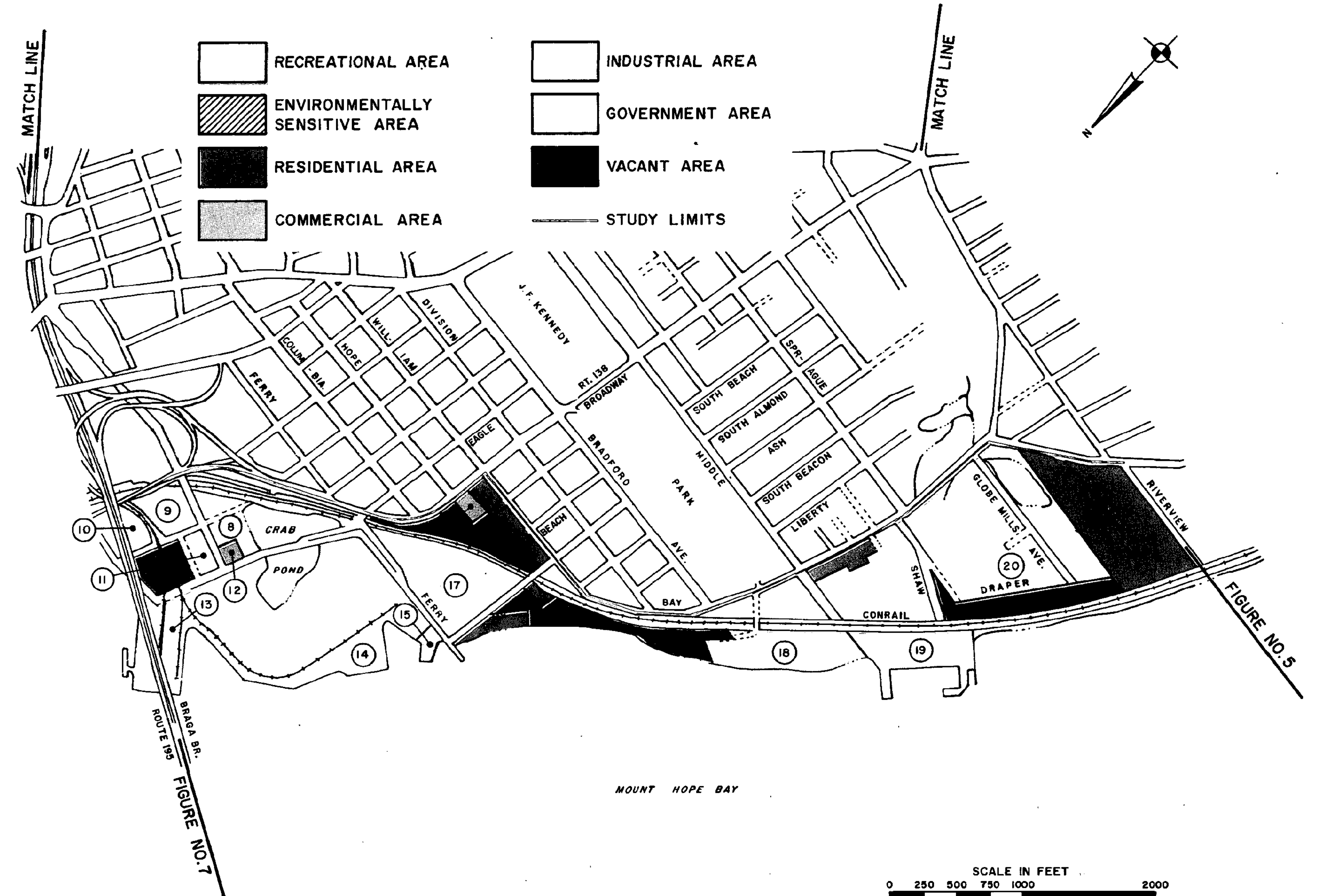


MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB. 1981	FIG. NO. 4



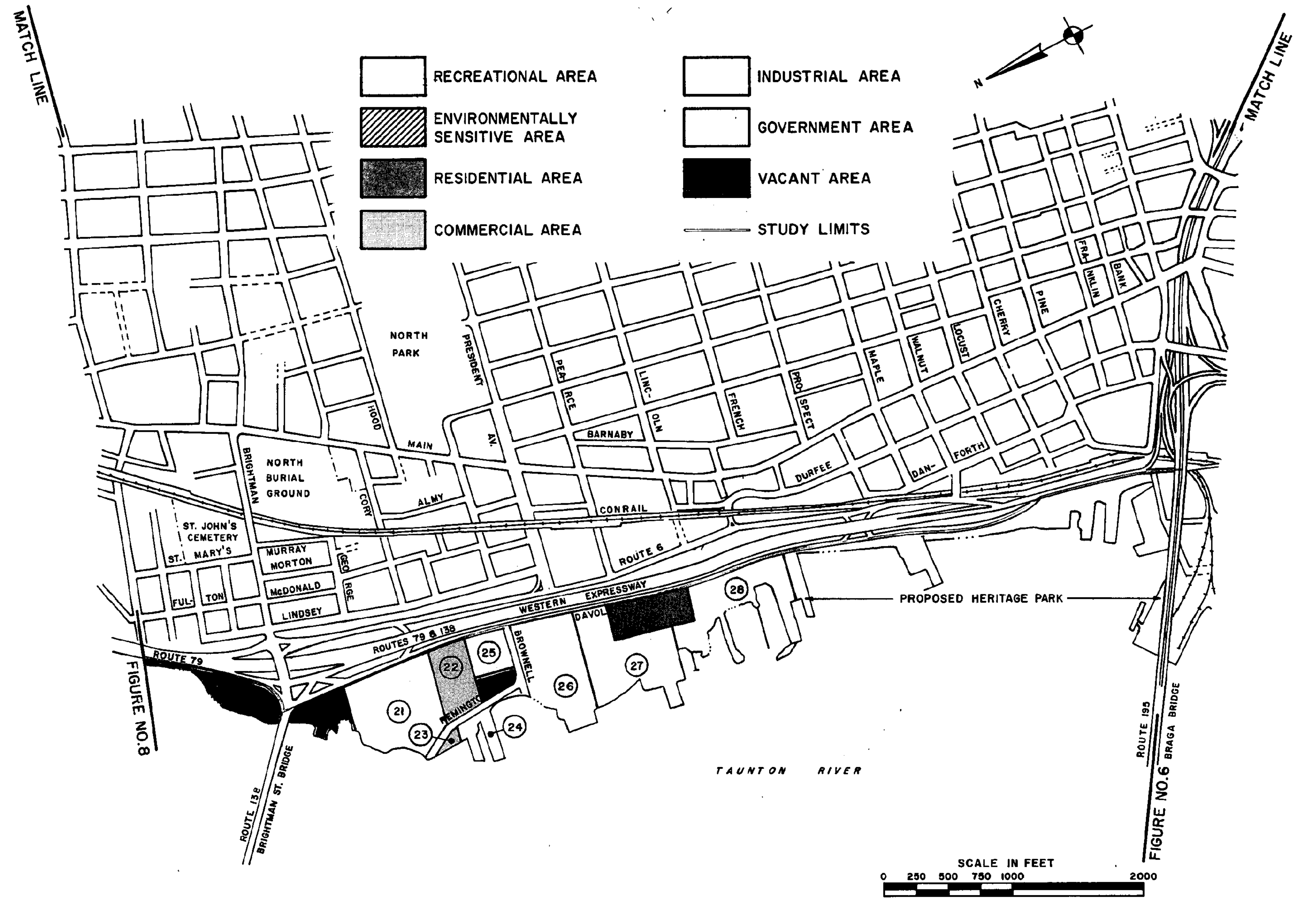
FOR IDENTIFICATION OF THE ACTIVITIES LOCATED IN EACH NUMBERED AREA, SEE TABLE NO. 1

MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB., 1981	FIG. NO. 5



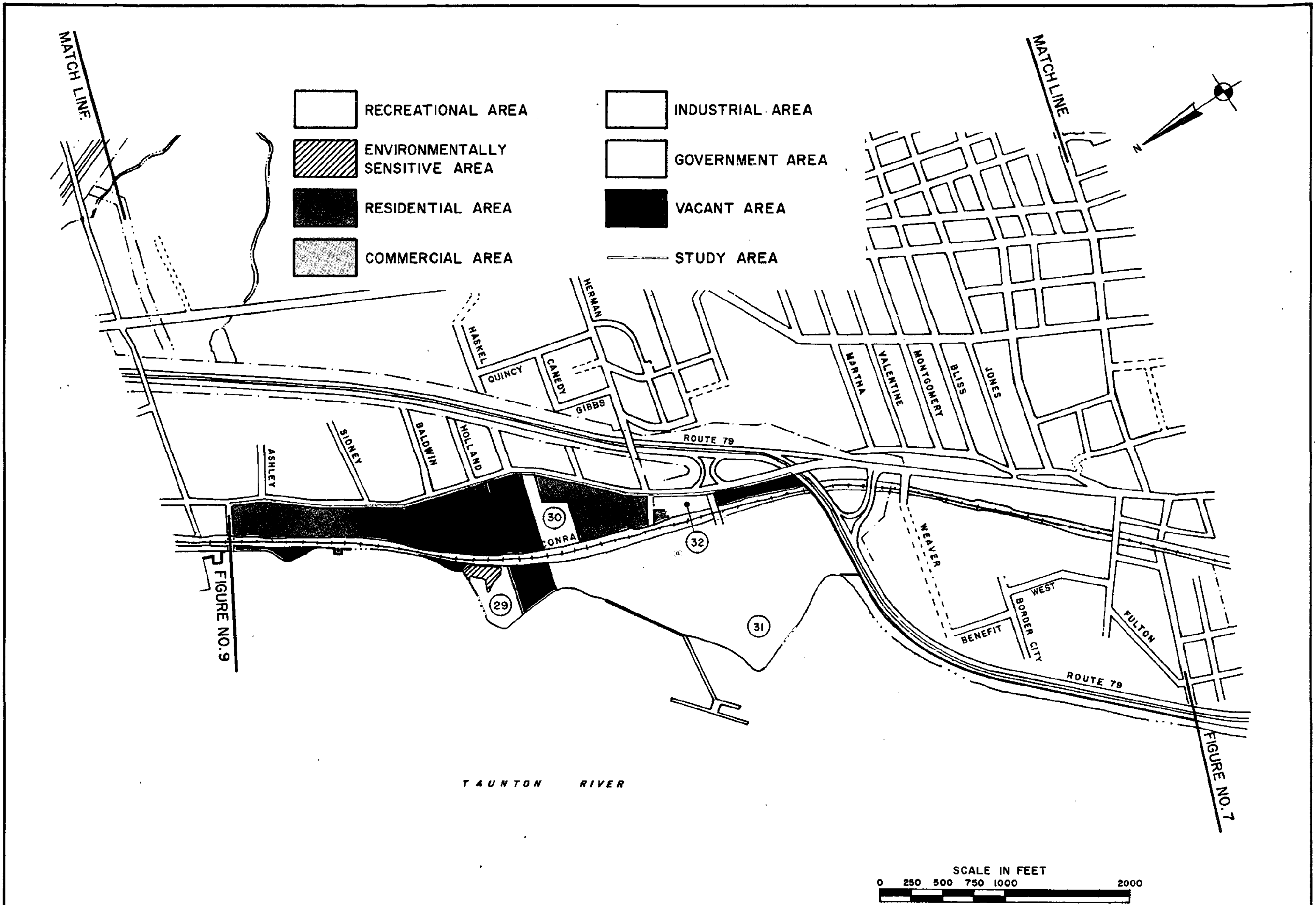
FOR IDENTIFICATION OF THE ACTIVITIES LOCATED IN EACH NUMBERED AREA, SEE TABLE NO. 2

MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB., 1981	FIG. NO. 6



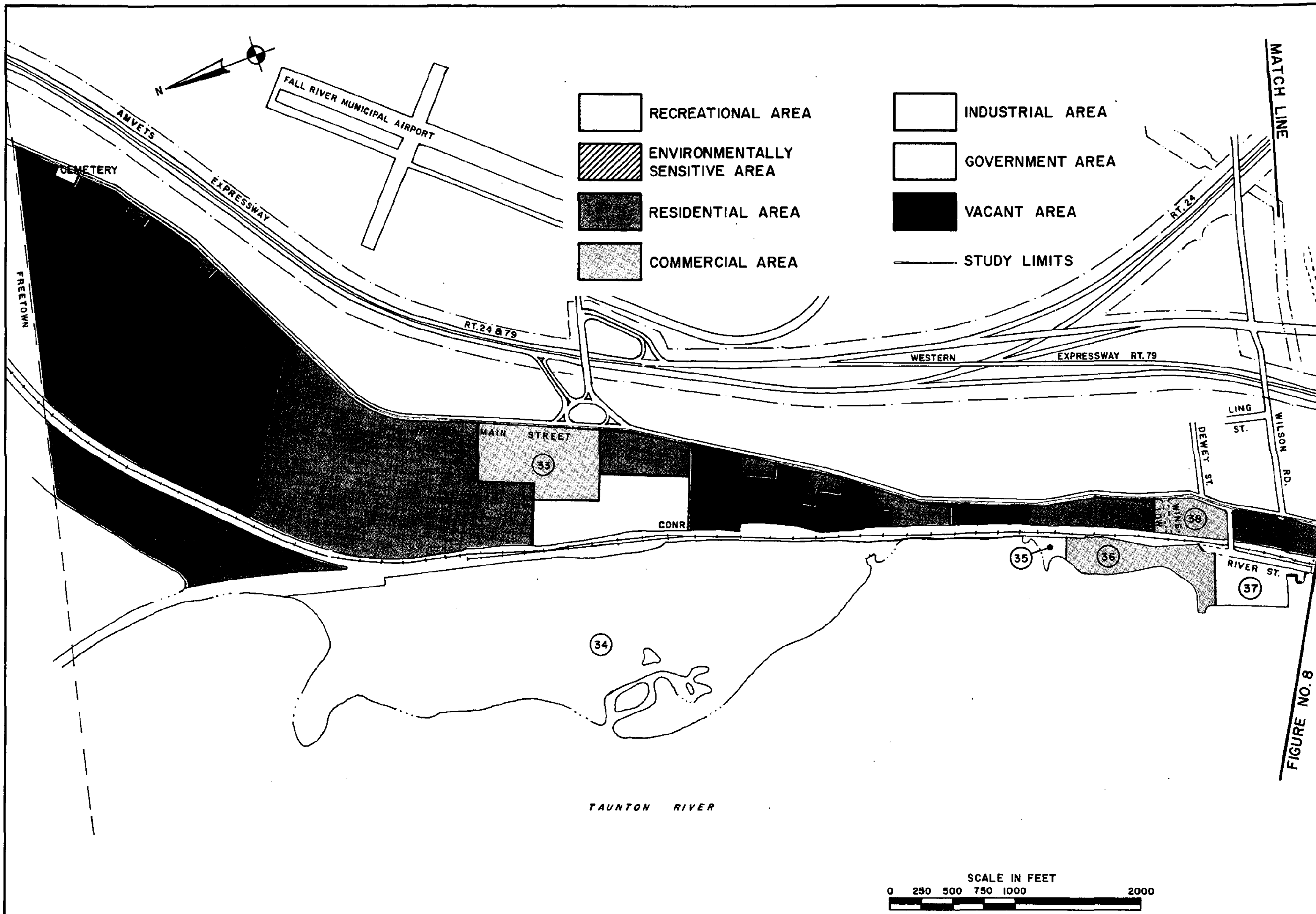
FOR IDENTIFICATION OF THE ACTIVITIES LOCATED IN EACH NUMBERED AREA, SEE TABLE NO. 3

MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB., 1981	FIG. NO. 7



FOR IDENTIFICATION OF THE ACTIVITIES LOCATED IN EACH NUMBERED AREA, SEE TABLE NO. 4

MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB., 1981	FIG. NO. 8



FOR IDENTIFICATION OF THE ACTIVITIES LOCATED IN EACH NUMBERED AREA, SEE TABLE NO. 5

MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB., 1981	FIG. NO. 9

limits, but it does not appear that the railroad will be a barrier to development of frontage property in all cases. In some areas, however, the railroad tracks are elevated above or submerged below adjacent sites, or the strip of land along the water is too narrow to be effectively utilized, and development of areas on both sides of the track as one site would be unlikely. In these cases, the railroad tracks are probably the practical onshore limit of waterfront development. In order to identify these areas, as opposed to areas where development across the railroad tracks is possible, the entire waterfront within the limits of major streets was studied. Development on both sides of the tracks will involve crossing of the main Conrail line and right-of-way, but it has been assumed that an arrangement to allow this is possible.

The activities located in the various land use areas are identified in Tables 1 through 5. For the purposes of this study, only those sites with potential for development by OCS or coastal energy activities are of interest. Based on the economics of the OCS industry and predicted levels of recoverable resources, it appears that only vacant or underutilized sites could be economically developed for OCS facilities. It is unlikely that demands by the OCS industry for waterfront sites in New England will justify dislocation of ongoing commerce or industry. Some marginal users of waterfront sites could possibly be displaced, but, for the most part, it appears that OCS support activities will locate on sites requiring little capital investment. Sites such

TABLE 1

Inventory - Figure 5

Area 1 - storage tanks, pumps

Area 2 - chemical facility

Area 3 - A & M Machine Shop

Area 4 - Fall River Gas Co.

Area 5 - Holsum Bakery
Fall River Gas Co.

Area 6 - Westrex-Litton
GTE

Area 7 - sewage treatment plant

TABLE 2

Inventory - Figure 6

Area 8 - Fall River Steam & Gas Pipe Co.
Fall River Gas Co.

Area 9 - Lamport Co.
A. Soloff & Sons

Area 10 - pumping station

Area 11 - SealSac
Victory Drapery & Curtain

Area 12 - Marine Museum

Area 13 - State Pier

Area 14 - Tillotson Complex
Northeast Products

Area 15 - Pollution Control Station

Area 16 - Gas Station

Area 17 - Travis Furniture
Providence Fabric Co.

Area 18 - King Phillip Boat Club
park

Area 19 - Sanchez Marine

Area 20 - JayDee Threadworks
Duro Textiles
National Roofing Co.
River Textiles
Ashworth Co.
Pioneer Finishing Co.

TABLE 3

Inventory - Figure 7

Area 21 - Santoro Manufacturing
Coca-Cola Bottling Plant
proposed Duzich facility (former Naval Reserve Center)

Area 22 - Pacquette's Auto Parts
Al & Paul's Auto Repairs
Reynolds Aluminum

Area 23 - Heritage Park Motors

Area 24 - Montaup Electric transmission towers

Area 25 - Quaker Mills
Ellison Paper

Area 26 - Bicentennial Park

Area 27 - Fall River Electric Co.

Area 28 - K-D Cove Marina

TABLE 4

Inventory - Figure 8

Area 29 - Montaup Electric transmission tower

Area 30 - telephone company

Area 31 - Shell Oil Co.

Area 32 - Massachusetts Dept. of Public Works

TABLE 5

Inventory - Figure 9

Area 33 - Sunnyland Farms
Elks' Club

Area 34 - Fall River Country Club

Area 35 - beach area

Area 36 - Hancock Marine

Area 37 - O'Connell Boatyard

Area 38 - lumber yard
veterinarian's office

as Davisville, possessing berthing areas and back-up space as well as a developed industrial infrastructure, are obviously of prime interest to the OCS industry, but few, if any, other sites with the capabilities of Davisville exist in New England. All other things being approximately equal, selection of development sites in other areas will, therefore, be based on minimizing capital investment requirements, by minimizing acquisition costs or development costs. Primary screening has identified the following sites as being of potential interest to this study:

- Site A consists of approximately 25 acres in several tracts along both sides of Slade Street and the waterfront. This site is included in Figure 5 and is bounded on the south by the Fall River Gas Co. (Areas 4 and 5), on the north by a residential area, and on the east by Bay Street. Portions of the site are occupied by unused storage tanks, cement platforms, and an existing chemical business. The remains of two pipeline piers extend outward from the shoreline. The land rises sharply from the water's edge to a cliff approximately 20 feet high, then rises gradually across the railroad tracks, rolling gently up to Bay Street. Approximately 1400 feet of waterfront are located across the tracks from the main portion of this site, and development would be contingent on development on both sides of the tracks, which are at the same approximate elevation as adjacent land.

- Site B is the site of the Sanchez Marine Company and consists of approximately seven acres and 2100 feet of waterfront. This site is shown as Area 19 on Figure 6. Approximately three additional acres of vacant land are located across the railroad tracks from the southern portion of the site. The site is flat, with the tracks approximately 10 feet above ground elevation, forming the eastern boundary. Approximately 1100 feet of berthing space have been created by a granite seawall retaining earth fill and Sanchez Marine has expressed a willingness to construct additional bulkheading along the southern portion of the site.

- Site C is the former Penn Central railroad yard and consists of approximately four acres, rising sharply from the water's edge to a small cliff approximately 20 feet high. The rest of the site is relatively flat. This site is included in Figure 6 and is bordered on the east by Bay Street, on the north by Almond Street, and on the south by a park and the King Philip Boat Club (Area 18). Interest has been expressed in this site as the offloading location for the coal plant proposed for Fall River.

- Site D consists of approximately 13 acres in two tracts. It is included in Figure 8 and is bordered on the south by a telephone company facility (Area 30), on the north by a residential area, and on the east by North Main Street. Approximately half of this area is the site of the former St.

Vincent's Orphanage, now demolished. The terrain is slightly rolling, but relatively flat. The railroad tracks separate the main portion of the site from the waterfront, but access could be achieved by concurrent development of site E or by bulkheading and filling along the waterfront portion of this site. Railroad tracks are at ground level at this location.

. Site E consists of approximately two acres opposite the southern end of site D. This site is also a portion of the former St. Vincent's Orphanage. The land rises sharply from the water's edge to an elevation of approximately 20 feet along the railroad tracks. This site is included on Figure 8 and is bounded on the north by the site of the Montaup Electric Company transmission tower (Area 29), running lines from the Montaup Electric generating plant directly across the river. The southern border abuts the Shell Oil Co. terminal, shown as Area 31.

. Site F is the site of the Hancock Marine Company and is shown as Area 36 on Figure 9. It consists of approximately 8 acres, with 1200 feet of waterfront. There is a pier, approximately 25 by 100 feet, consisting of earth fill enclosed by a stone retaining wall. The site rises from the beach to an elevation of approximately 35 feet at the eastern boundary which is formed by the railroad tracks.

Hancock Marine is an ongoing marine-related industry and the owner has expressed interest in OCS activities locating there, providing that can be accomplished with minimal disruption to his business and residence, which is also located on the site.

- Site G is separated from site F by the railroad tracks. It is shown as Area 38 on Figure 9. The site is currently occupied by a lumberyard and consists of approximately three acres of flat land. Development of this site is contingent on OCS-related use of site F or other nearby waterfront sites. Use in connection with site F would require improved bridging of the railroad tracks, which are below grade at this point.

- Site H consists of approximately 94 acres located in the northernmost portion of town. It is included on Figure 9. The area is completely wooded and is bounded by North Main Street on the east, the railroad tracks on the west, and a residential area on the south. The site slopes upward from the railroad tracks to North Main Street.

- Site I is separated from site H by the railroad tracks and consists of approximately 17 acres. It is bounded on the west by a cove formed by an old earthen railroad trestle, now unused. There is a small sandy beach along the water's edge from which the terrain rises sharply to the railroad tracks. This site is undeveloped and contains approximately 800 feet of waterfront.

III. OUTER CONTINENTAL SHELF (OCS) DEVELOPMENT

A. OCS Operations

Exploration for and production of oil or gas from the Outer Continental Shelf (OCS) requires a variety of shore support facilities. Equipment, supplies and personnel must be transported to the platform, and oil and/or gas must be transported to shore.

Due to the enormous costs and potential hazards associated with offshore drilling, requirements for specialized personnel and material necessitate a quick and reliable response. Many of the shoreside support facilities are unique and require specialized equipment and trained personnel, so firms with previous experience in OCS operations in other areas generally establish operations in a "frontier" coastal region adjacent to new offshore activity. Although some opportunities exist for indigenous industries, most of the support services described below will be provided by firms with previous experience in OCS activities. Employment opportunities for local labor do exist, however, since as many as 80 percent of the jobs can be filled by local workers with no previous OCS experience.

OCS activities proceed in three general phases. In the first phase, exploration, a program of geophysical investigation is conducted to locate geological formations which may contain reservoirs of oil or gas. Once potential areas are identified, exploratory drilling is conducted to determine if commercial quantities of hydrocarbons are present. Exploratory drilling is conducted from a barge, drill ship, semi-submersible platform or jack-up platform. The latter two are the most common. Both platforms are floated to the drilling area, but the legs of a jack-up or self-elevating platform are then jacked downward to the sea floor and the platform is raised above the water surface, while a semi-submersible platform remains afloat, supported by displacement hulls or caissons. During this phase, limited shore support facilities are required and most of those are temporary, often operating out of leased space. The major shore activity required during this phase is support from service bases and suppliers of tubular goods and drilling supplies, such as mud and cement.

If oil or gas are found in commercial quantities, development of the field, the second phase, begins. Most development drilling takes place from fixed platforms, which are floated to the site and positioned by means of piles driven into the sea floor. An alternative to the fixed platform is the subsea production system, which involves placing the wellhead directly on the sea floor. This system is a recent development and is not as common as fixed platforms but can reduce costs when used successfully in deep water. During the development phase shore support activity is at its height, as wells are drilled, platforms are constructed and installed, and gas/oil transport systems are constructed. Permanent service bases are established during this phase, as well as ancillary industries such as repair and maintenance yards, catering services, tool and equipment companies, diving companies, and other companies performing specialized services related to drilling equipment.

Once development is completed, the drilling rig is disassembled, production equipment is installed on the platform, transport systems are implemented, and the third phase begins. Oil may be pumped ashore by pipeline or pumped to offshore storage tanks for transport by tankers. In general, it is preferable to pipe crude oil to shore. Depending on the existence of local refinery capacity and market conditions in adjacent coastal areas, crude oil may be transported to a nearby refinery or to a refinery in an area with a greater demand for petroleum or a greater refinery capacity. Gas must be piped to shore. Gas processing and treatment facilities are generally located between the OCS pipeline landfall and a connection to the existing pipeline transmission system.

The location of onshore support facilities primarily depends on the location of the resources and availability of facilities or developable sites. Service bases generally locate reasonably close to offshore operations to minimize travel time, and activities that utilize service bases to transport personnel, equipment or supplies locate nearby. An additional siting consideration is the tendency of OCS support activities to "cluster" in a few port areas. This cluster tendency is a result of the frequent need for cooperation and interaction among the support activities, as well as the close relationships that often exist among firms and personnel. This grouping of activities also tends to minimize duplication of facilities and equipment, maximize efficiency, and insure quick and reliable response to the needs of the OCS industry.

In order to support OCS operations, a variety of onshore support facilities are required. The number and location of these facilities depend on a variety of factors, including:

- size of the find;
- location, depth, topography of the field;
- whether or not both oil and gas are found;
- availability of waterfront and back-up land with necessary infrastructure;
- availability of existing gas pipelines, processing plants, or oil refineries nearby.

The following sections describe typical onshore OCS support facilities, along with their requirements, potential impacts, and siting considerations.

B. Typical OCS Onshore Support Facilities

1. Service Bases

Service bases serve as transfer points for transport of material and personnel to offshore operations. Transport to offshore facilities is by water or air, while transport to onshore facilities is by rail, road, air, or water. Service bases may be established by oil companies or by specialized companies operating under contract. A service base can support as many rigs or platforms as its facilities and space permit. Generally, two to three supply boats, one crew boat, and at least one helicopter are needed to support each drilling rig or platform. More vessels and helicopters may be necessary if a rig is located a long distance offshore, isolated from other OCS operations. Economies of scale may occur when several rigs are operating in the same general area, and fewer vessels and helicopters are needed. A service base needs at least two berths for each rig it is supporting, or approximately 400 feet of berthing space. A helipad is also necessary. Depending on the distance to the rig and the nature of operations, at least one vessel trip and one helicopter trip per rig are required each day, although this can vary considerable. If OCS operations are located greater than 100 to 150 miles offshore, helicopters may replace crew boats for transporting personnel, except when a large number of workers must be transported.

Based on an active rig drilling four 15,000 foot wells per year, the following volumes of material would be required:

13,000	barrels of fuel
2,500	tons of drilling mud
1,250	tons of cement
5,200,000	gallons of fresh water
1,800	tons of tubular goods

Most of these materials generally arrive at the service base by land, making good rail and highway access a necessity. Some material may arrive by water and, of course, most material is transported to the rigs by water, therefore good water access is also necessary.

Temporary service bases are generally established soon after a lease sale to support exploration and early development activities. These bases may be established by or in connection with drilling supply companies. Once significant finds are made, permanent bases are established as close as possible to offshore activities. These permanent bases may be developed by expansion of temporary facilities, depending on the location of the find and adequacy of the temporary sites. Smaller service bases, generally temporary, are also required for installation of platforms and pipelines. Pipeline installation service bases generally locate close to the pipeline route and supporting pipe coating yards. Since platform fabrication yards are relatively rare, platform installation service bases generally locate close to the installation sites.

Service bases require large areas for open and covered storage, as well as a marginal wharf. They also require maintenance, administration, and communication facilities.

The location of service bases is particularly critical, since many related support industries will locate nearby to utilize the service base area as a transfer point.

a. Requirements

Land:	5 - 15 acres for a temporary base 25 - 100 acres for a permanent base
Waterfront:	200 - 600 feet, 15 - 20 feet deep
Water:	5 - 8 million gallons/rig or platform/year during drilling
Energy:	13,000 - 50,000 barrels of fuel/platform/year

b. Impacts

Labor:	50 - 60 jobs/platform during drilling 20 - 30 jobs/platform during production
Wages:	$1,250,000/year
Capital Investment:	$200,000 - $300,000 for a temporary base $2 - $5 million for a permanent base
Air Emissions:	hydrocarbons carbon monoxide nitrogen oxides

Wastewater Contaminants:	hydrocarbons heavy metals
Noise:	up to 85 dBA on a 24-hour basis
Solid Wastes:	up to 6 tons per day during drilling, including hazardous, oil contaminated wastes

2. Transportation Facilities

The two primary alternatives for transporting oil and gas from offshore production facilities to onshore processing or storage facilities are pipelines and tankers. Gas must be transported by pipeline, but oil can be transported by either pipeline or tanker. The method of transportation for oil depends on the size of the find, distance from shore, topography over which a pipeline must run, meteorological conditions and availability of pipeline landfall sites. Existence of a refinery and market demand in adjacent coastal areas for the oil are also factors. Pipelines are the preferred method of transport as they are generally safer, more economical to operate and are not affected by weather conditions. Pipeline installation is expensive, however, so companies constructing pipelines attempt to minimize the length required by selecting the shortest possible route. In the United States, approximately 98 percent of all offshore oil is brought ashore by pipeline.

a. Pipelines

The following factors encourage use of pipelines:

- large volumes of oil and/or gas;
- reservoir located near shore;
- relatively mild topography between field and landfall;
- harsh weather conditions;
- existence of refinery or processing facilities and/or market area in adjacent coastal areas.

In general, production of approximately 70,000 to 150,000 barrels per day of oil or 500 million cubic feet per day of gas is necessary to justify construction of a pipeline.

Shore support facilities required for construction and operation of a pipeline include service bases to support pipeline installation, pipe coating yards, landfalls and easements and, possibly, pumping stations. Most facilities operate mainly during construction of the pipeline, which could last up to three years. Testing and inspection services, diving companies and surveying teams are also required and are discussed in Section 7. Depending on the ultimate destination of the oil or gas, a refinery or processing plant, marine terminal, or storage facility could also be required. Requirements and impacts of these facilities are discussed in the following sections. Requirements and impacts associated with pipeline construction and operation are presented below.

(1) Requirements

Land:	50-100 foot easement for landfall 40 acres for pumping station if required 50 - 150 acres for pipe coating yard
Waterfront:	50-100 feet for landfall 750 feet for pipe coating yard, at least 10 feet deep
Water:	18,000 - 20,000 gallons per day
Energy:	1 million KwH 12 - 13 million cu. ft./yr. of gas

(2) Impacts

Labor:	250-300 jobs/pipeline during construction 100-200 jobs at pipe coating yard during pipeline con-construction
Wages:	$6 million/year for pipeline during construction $2 million/year for pipe coating yard during pipeline construction
Capital Investment:	$10 - $12 million for pipe coating yard
Air Emissions:	hydrocarbons sulfur oxides nitrogen oxides particulate matter carbon monoxide

Wastewater Contaminants:	hydrocarbons alkaline substances particulates metal fragments
Noise:	up to 100 dBA on a 24-hour basis
Solid Wastes:	packaging materials concrete metal scraps contaminated debris

b. Marine Terminals

In general, the following factors encourage use of tankers to transport crude oil:

- scattered finds, little gas
- long distance to shore
- rough seafloor terrain
- no refinery or market in nearby coastal areas

The primary onshore support facilities required by tankers are marine terminals and tank farms. Refineries may also be required, depending on the ultimate destination of the crude oil.

Marine terminals may receive crude oil from tankers for overland delivery to refineries or may receive it by pipeline from offshore production facilities for delivery to refineries. In the early stages of production, even if pipelines are to be used, small tankers (16,000 - 25,000 deadweight tons) are generally used to transport crude oil from the offshore platforms until the pipelines can be constructed. While pipelines are being constructed, gas is generally reinjected into the field for future extraction or "flared" (burned off).

Configurations of marine terminal facilities differ depending on the use of the terminal and the availability of waterfront and back-up land. Berthing facilities can include offshore moorings, fixed sea island piers or fixed shoreside piers.

(1) Requirements

Land:	60 acres for terminal 40-60 acres for tank farm
Waterfront:	Up to 1,000 feet for shoreside pier, at least 35 feet deep
Water:	to replenish potable supplies ballast and/or purging
Energy:	up to 8 million KwH/year

(2) Impacts

Labor:	25-65 jobs
Wages:	$500,000 - $1,000,000/year
Capital Investment:	$15 - $50 million
Air Emissions:	hydrocarbons carbon monoxide
Water Emissions:	high BOD high COD oil and grease chronic small oil spills

3. Processing and Treatment Facilities

The crude oil wellstream produced at the wellhead consists of crude oil, natural gas, brine water and suspended and dissolved solids. The nature and location of facilities to treat and process this stream vary depending on the characteristics of the stream and transportation strategies. The first step, partial processing, is designed to remove impurities and separate associated gas from the wellstream. Gas found in a free state, with no oil present, is known as non-associated gas. Generally, the separation of associated gas occurs at the platform, and the gas is piped ashore for treatment, to remove impurities, and for processing, to recover valuable liquefiable hydrocarbons. Associated gas may be flared if volumes are small or may be reinjected into the reservoir. In some cases, the entire wellstream is pumped ashore, eliminating the need for separate gas and oil pipelines. Once the associated gas and impurities are removed, the wellstream consists of oil and free and emulsified water. Often, separation of the free water also occurs on the platform, although sometimes the entire liquid wellstream is piped ashore, reducing the efficiency of the pipeline since unnecessary liquid (water) is being transported. This decision involves an assessment of the increased pump and pipe sizes needed to carry the volume increases due to free water, against the use of valuable platform space for separation equipment. Equipment used for the separation of emulsified water is relatively complex and is generally located onshore. Both free and emulsified water must be treated before discharge. If tankers are used for transport, an offshore storage facility is required, and partial processing facilities for crude oil can be located there.

In general, separation of associated gas and removal, treatment, and discharge of free water occur on the platform, while gas processing and treatment, and removal of emulsified water occur onshore. As stated previously, however, these decisions depend on the characteristics of the wellstream, the method of transport and distance from shore.

a. Requirements

Land:	50-75 acres
Water:	200,000 - 750,000 gallons/day
Energy:	6,000,000 KwH/month 360,000,000 cubic feet/month of gas

b. Impacts

Labor:	50-60 jobs
Wages:	$750,000 - $1,000,000/year
Capital Investment:	$50 - $100 million

Air Emissions:	hydrocarbons hydrogen sulfides sulfur oxides nitrogen oxides carbon monoxide particulates
Wastewater Contaminants:	suspended solids oil, grease heavy metals phenols halogens chromium sulfuric acid zinc chlorine phosphates
Noise:	up to 100 dBA from boilers, compressors, pumps on a 24-hour basis
Solid Wastes:	scale and sludge oil absorbants spent desiccants

4. Refineries

In general, there is no direct correlation between the discovery of commercial quantities of crude oil in an OCS area and construction of new refineries in adjacent coastal areas. There are three basic types of refineries: market, resource, and swing. Market refineries serve a particular market demand area; resource refineries are built on or near major oil fields; and swing refineries balance supply and demand for particular refined products in several consumer areas. The oil industry prefers to build market refineries, since it is cheaper to ship bulk crude oil than several refined products. Refineries are constructed in connection with OCS production areas, therefore, only when a market area is nearby and no existing refineries are present.

A modern oil refinery is an automated facility consisting of a series of units which physically or chemically alter all or part of the crude oil stream to produce a number of petroleum products. Storage tanks, administration and maintenance facilities and water treatment facilities are also located at a refinery, and the entire complex is generally surrounded by a buffer zone. Transportation systems, which could include a marine terminal, pipeline, roads, and rail, are also required.

a. <u>Requirements</u>

Land:	1,000 - 2,000 acres
Water:	5-10 million gallons/day
Energy:	2,000,000 - 4,000,000 KwH/day 25,000 - 50,000 barrels of fuel oil/day

b. <u>Impacts</u>

Labor:	400-600 jobs
Wages:	$6-$10 million/year
Capital Investment:	$200 million - $500 million
Air Emissions:	particulate matter sulfur oxides carbon monoxide hydro carbons nitrogen oxide aldehydes ammonia

Wastewater Contaminants:	floating and dissolved oil suspended solids dissolved solids dissolved organics cyanide chromate organic nitrogen phosphate sulfides and mercaptans caustics and acids
Noise:	up to 100 dBA from compressors, boilers, furnaces, blowers, and cracking units on a 24-hour basis
Solid Wastes:	sediments sludges residues waste paper, cardboard food wastes packaging materials ashes, dust bottles, cans insulation, building materials general refuse

5. Repair and Maintenance Yards

Facilities for repair and maintenance of the various OCS-related vessels, platforms, rigs, and equipment are required to support offshore operations. Vessels include workboats, crewboats, tugboats, supply boats, utility boats, a variety of barges, research and seismic vessels and diver tenders. These vessels generally range from 60 to 250 feet in length, averaging about 175 feet, and are often equipped with specialized equipment. They are generally too large to be serviced in a yard designed for pleasure craft, but not large enough to justify use of a large shipyard. Since these vessels are about the same size as fishing vessels, they can generally be well-serviced by facilities which support fishing fleets. This type of facility is not unique to OCS operations, so indigenous repair and maintenance facilities in a coastal area are generally able to capitalize on the needs of the OCS industry.

Repair and maintenance yards must be located near the OCS operating area and, if possible, near service bases. Location of an adequate repair and maintenance yard can be a consideration in the siting of service bases, since vessels operating out of a service base will require regular maintenance and occasional repairs, and will want to minimize the travel distance to and from the yard, if possible. Since development of a repair/maintenance yard requires a large capital investment, new repair and maintenance yards are generally not established in response to OCS demands; rather, existing yards expand or augment their facilities to meet the demand. Requirements and impacts, therefore, are incremental in nature, depending on the location and size of existing facilities.

6. Platform Fabrication Yards

Platforms used in OCS operations can be constructed of steel or concrete. Steel platforms consist of a main body, called a pile jacket, which is constructed almost entirely of tubular steel members. The jacket is constructed onshore near the waterfront. It may be floated to the installation site or placed on a barge and towed to the site, where it is set in place and pinned to the seabed by large diameter steel pilings. The deck and individual components - drilling rig, living quarters, helipad, operations facilities and other modules - are also constructed onshore, towed to the site and attached to the platform.

Like steel platforms, concrete platforms are constructed at waterfront sites. Concrete platforms, however, are constructed in large, deep dry-dock basins separated from deep adjacent waters by a cofferdam. Deck modules are often manufactured elsewhere and fastened to the platform base when it is in place. Unlike steel platforms, concrete platforms depend on gravity, rather than anchor piles, to hold the platform in place. The type of platform is determined by the mix of oil and gas in the find, meteorological and foundation conditions, and topography of the find area. If offshore storage and loading facilities for tankers are necessary, concrete may be used since concrete platforms can accommodate storage capacity more easily than steel platforms.

Yards for construction of either type of platform are basically large, industrial facilities. Components of a steel platform fabrication yard include a fabrication shop for preparing pipe and plate, pipe mill and welding rack. For a concrete platform fabrication yard, the components include one or more large, deep, dredged dry dock basins, concrete mixing plant and cement storage silos.

a. Requirements

	Concrete	Steel
Land:	20 - 50 acres	400 - 800 acres
Waterfront:	400 feet, 20-50 feet deep	200 - 350 feet, 15-30 feet deep
Water:	40,000 gal/day	100,000 gal/day

b. Impacts

	Concrete	Steel
Labor:	350-450 jobs	250-550 jobs
Wages:	$10 million/year	$30 million/year
Capital Investment:	$40-$80 million	$40-$80 million
Air Emissions:	sand & metal dust concrete and cement dust hydrocarbons carbon monoxide organic compounds sulfoxide nitrogen oxide	sand & metal dust hydrocarbons carbon monoxide sulfoxide nitrogen oxide
Wastewater Contaminants:	heavy metals particulates chemicals	heavy metals particulates chemicals

Noise:	80 - 100 dBA on a 24-hour basis	80 - 100 dBA on a 24-hour basis
Solid Wastes:	pkg. material metal scraps contam. debris	packaging material metal scraps contaminated debris

7. <u>Ancillary Industries</u>

In addition to the onshore activities directly involved in support of OCS operations, there are a variety of additional services required by the offshore industry. These industries provide services, materials, equipment, and personnel to the offshore industry. Some of the services can be provided by indigenous businesses, while others are specialized and are generally provided through the establishment of local operations by a firm involved with the OCS industry in other areas. Some of the ancillary industries that can be expected to locate in a coastal area adjacent to OCS operations are discussed below.

a. <u>Drilling supply companies</u> include mud and cement suppliers. Mud companies provide drilling fluids and engineering services to drilling contractors. These fluids are used to cool the drill bit and string, retrieve rock cuttings, control subsurface pressure and coat the exposed walls of the hole. Due to the high level of specialization and expertise required in this operation, it appears unlikely that indigenous businesses in an OCS-support area could provide this service. Facilities required for a mud company include a marginal wharf, warehouse, office and laboratory; these facilities should be served by rail and road. A mud company facility may utilize a portion of a service base or serve as a service base, allowing use of its berths by offshore operators who contract for mud.

Cement companies provide specialized cementing services for OCS drilling operations. Cement is blended in specific proportions and pumped down the well hole to cement the steel casing and seal the hole. As with mud companies, it is likely that these services will be provided by cement companies with previous experience in OCS operations that establish operations in a frontier area. Local companies might, however, supply bulk cement. Facilities for this type of company include berthing space, warehouse and bulk storage area, laboratory and office, and must be well served by road and rail systems. As with mud companies, cement companies may operate through or utilize a portion of a service base or may contain their own berthing facilities, sometimes serving as a transfer point for other OCS support activities.

b. <u>Tool and equipment companies</u> supply the tools and equipment required during drilling and production that are too specialized and/or expensive to be provided on each rig. These can include drilling tools, equipment used to control the flow of oil and gas at the wellhead, fishing tools used to retrieve downhole equipment, directional drilling equipment and others. There are several major companies involved in this industry, and they generally establish local operations to service OCS frontier areas. Personnel may be provided by these companies to supervise the installation and maintenance of the equipment. Facility requirements include warehouse and open storage areas, office and shop. The site should have good access by road and, if possible, rail, as well as access to berthing facilities. These companies tend to locate near service bases, since those are the transfer point for delivery to OCS operations.

c. <u>Logging and perforating companies</u> provide equipment and personnel to evaluate ("log") and perforate wells. During logging, an electronic device is lowered into the hole to measure the properties of various formations. Perforation involves punching of holes in the well casing to allow pressurized oil and gas to enter the casing and rise to the surface at the wellhead. Facilities include an office, laboratory, warehouse, and shop.

d. Helicopter companies transport crews and supplies and provide emergency services to offshore operations. Generally, a helicopter company will service a number of platforms. The company will locate at an airport or other site where storage, maintenance and fueling facilities exist. Each support base generally has a helipad and, possibly, a fueling station, but overnight storage of the helicopters is provided at the main facility. The helicopter company owns, operates and services its own helicopters. In general, helicopter companies with experience in support of OCS operations will establish facilities in a new OCS area. Mechanics, and eventually pilots, may be hired locally. A helicopter facility includes a helicopter landing area, a number of helicopter parking areas or helipads and an area or hangar for maintenance and repairs.

e. Catering services provide food and housekeeping services to offshore rigs and platforms. Catering companies provide all personnel, food and linens.

Some opportunities exist for local firms to expand into this area, but it is likely that firms with previous experience in OCS support will also establish local operations. Local labor and food purveyors may be used by the catering services, however. Facilities generally include a warehouse, office and, possibly, a kitchen or butcher shop.

f. <u>Diving service companies</u> provide divers and equipment for underwater construction, inspection and maintenance in support of OCS operations. Because of the highly specialized nature of the work, it is likely that the bulk of the work will be captured by established diving firms familiar to the OCS industry. Local divers may be employed after additional training, and some work may be subcontracted to local diving firms. Facility requirements include warehouse, equipment maintenance facilities and office space.

g. <u>Completion and production service companies</u> provide specialized equipment and services once a development well has been drilled. This equipment controls the flow of fluids from the reservoir to the surface and these companies also perform some remedial work. This is a highly specialized industry, offering little opportunity for indigenous firms. A typical facility includes an office, warehouse and maintenance building.

h. Inspection and testing companies provide equipment and personnel to inspect tubular goods, test and inspect pipelines, and inspect structures and equipment. These are highly specialized operations and offer few opportunities for indigenous firms but could involve local skilled and unskilled labor. Since most of the work is done in the field or at the customer's site, facility requirements are minimal, consisting basically of a small office, storage area and shop.

i. Trucking and stocking companies provide bonded storage and transportation services for the OCS industry. These firms receive stocks (mainly tubular products) from steel mills, store them until requested by offshore operators, then deliver them to the operators. These companies may also handle acquisitions for oil companies or drilling contractors. Because costs of maintaining an inventory are high, steel companies prefer that oil companies maintain stocks, while oil companies prefer that steel companies maintain them. Depending on prevailing market conditions, one or the other will approach a stocking company with regard to establishing a yard. Established OCS firms generally locate in the support area to provide these services. The primary facility requirement for this type of operation is a large land area. A large company can require over 100 acres of land for storage; a small office is also necessary.

j. <u>Fabrication, welding and machine shop services</u> are ancillary industries in which indigenous firms can capture a share of the market. Some large firms offer a complete range of services, including fabrication of specialized platform modules, while other firms provide only welding or machine shop services. Large firms generally are involved with other OCS operations and establish operations in an OCS frontier area, but local firms can also get a share of the business. Facility requirements depend on the range of services provided. Large firms may require up to 50 acres of land with berthing facilities, while smaller operations may be located on less than an acre with good access to nearby service bases.

k. <u>Labor contractors</u> provide a variety of skilled and unskilled workers on a contract basis. Facility requirements generally involve only an office.

l. Oil spill recovery services are a relatively recent development resulting from increased offshore drilling and a growing awareness of environmental concerns. Areas that presently support water-borne transport of petroleum and/or chemicals typically have existing spill recovery firms that can expand into OCS operations. Spill recovery and containment services generally operate under contract to oil companies, the U.S. Coast Guard, port authorities, or terminal operators. Facility requirements depend on the size of the operation. In general, up to 10 acres of land, with up to 1,000 feet of berthing space, a warehouse, office and machine shop are required.

m. Supply and service companies provide a wide range of miscellaneous supplies and services to the OCS industry. Supplies can include tools, equipment and office supplies, while services can include making travel arrangements for crews and arranging housing and schooling for the families. This business offers good opportunities for indigenous firms or entrepeneurs. Facility requirements vary greatly, but land requirements can range up to 50 acres with most of the space used for warehousing, open storage and an office.

n. <u>Petrochemical plants</u> convert feedstocks of raw materials and components of hydrocarbon mixtures into pure chemicals. As with oil refineries, petrochemical plants may or may not be established in response to offshore finds. Petrochemical plants can vary considerably in size, complexity, and the level of processing performed, ranging from primary processing plants which convert feedstocks into primary petrochemicals such as ethylene, propylene, butylene, benzene, toluene and mixed xylenes, to petrochemical complexes which process the primary petrochemicals through the intermediate and final stages. Intermediate petrochemicals include ethylene oxide, ethylene glycol, propylene oxide, phenol, styrene and vinyl chloride. Final petrochemical products include plastics, synthetic fibers, synthetic rubbers, paints, industrial solvents, drugs, explosives, fertilizers and pesticides.

The feedstock consists of liquified hydrocarbons from natural gas processing plants and naptha and gas-oil from refineries. In the past, natural gas liquids were the preferred source since they were abundant and cheap. In the future, however, petrochemical plants will be more dependent on naptha and gas-oil because of declining natural gas production. As much as 30,000 barrels per day of feedstock can be required by a one billion pound per year primary petrochemical plant.

Petrochemical plants locate near sources of raw materials - gas processing plants and refineries-in order to minimize the cost of transporting the feedstock. The primary components of a petrochemical plant are processing equipment, storage facilities, utilities (steam, gas, air, electricity, water), service and maintenance facilities and a buffer zone to reduce hazards and minimize impacts on adjacent areas. A primary petrochemical plant can require 200-350 acres, while a petrochemical complex can occupy as much as 5,000 acres. Petrochemical plants need not be located on waterfront sites.

Impacts of petrochemical plants vary with the type and size of the plant. Emissions, wastewater contaminants, water and energy demands, noise, solid waste and increased and contaminated runoff are of particular concern.

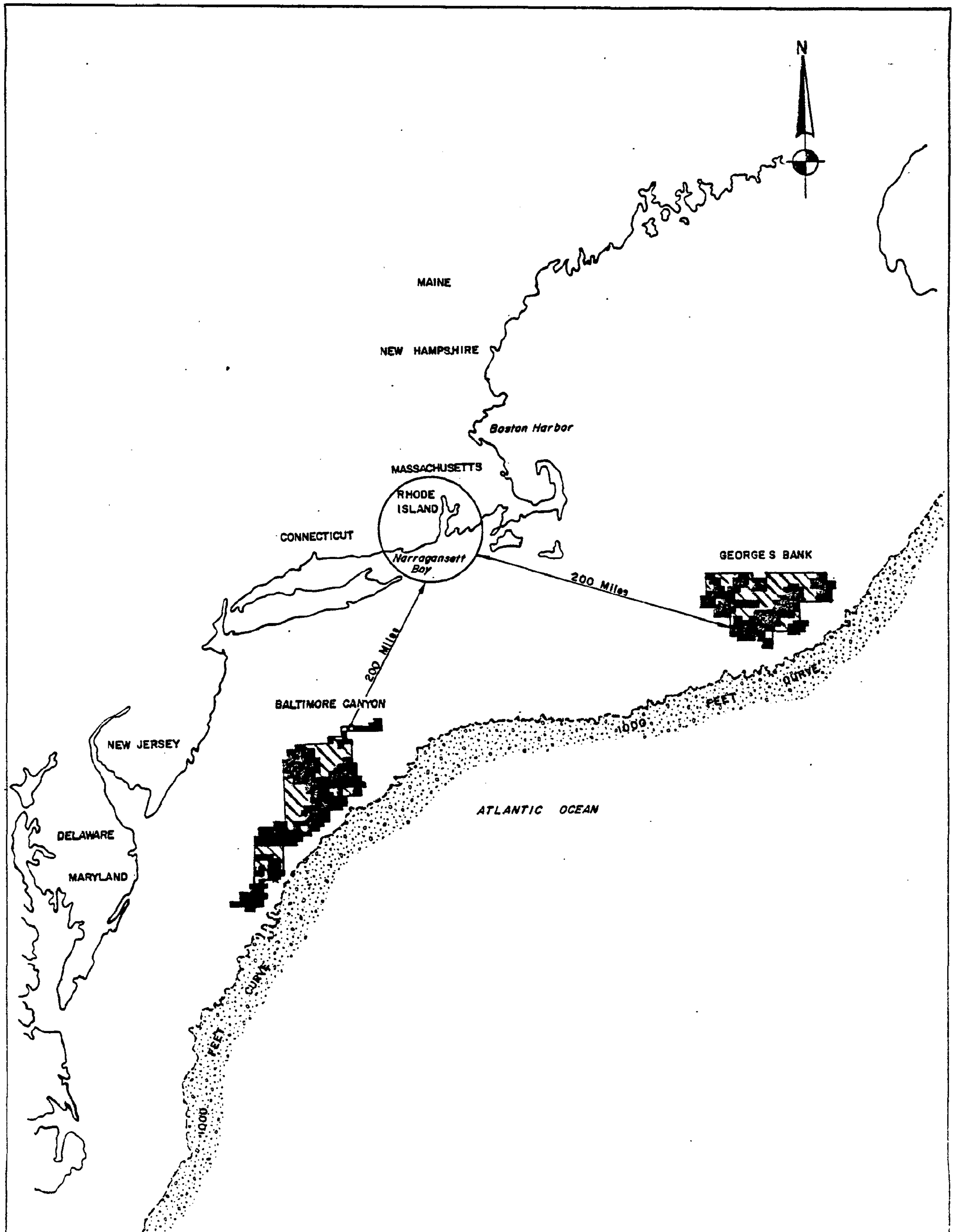
It is likely that future petrochemical plants will be developed by expansion of existing plants or built as part of very large refinery/gas processing/petrochemical complexes. These complexes would likely be located on large, isolated sites in areas where raw materials are readily available.

IV. OCS DEVELOPMENT SCENARIOS

Fall River could be impacted by offshore activity in both the North and Mid-Atlantic OCS Regions, as well as activity on the Grand Banks and Labrador Shelf in Canada. Due to its location in Narragansett Bay (see Figure 10), Fall River could serve as a support base for operations on both Georges Bank and the Baltimore Canyon, while a high level of activity in Canadian OCS fields could result in the establishment of support facilities north of Cape Cod to service both Canadian and Georges Bank operations. For the purposes of this study, it has been assumed that development of Canadian resources will be supported primarily from facilities in Halifax, Nova Scotia, and St. Johns, Newfoundland; operations on Georges Bank will be supported from facilities located in New England, and support for activity on the Baltimore Canyon will come from bases in Mid-Atlantic and New England states.

Risked resource estimates have been used to determine levels of development. Risked estimates differ from conditional estimates in that conditional estimates assume that economically recoverable resources will be discovered, while risked estimates consider the possibility of no finds occurring. Risked estimates used in this study are shown below:

	Mid-Atlantic OCS Region[1]	North Atlantic OCS Region[2]
Oil (billions of barrels)	.530	.356
Gas (trillions of cubic feet)	4.11	1.78



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Sources:

1. Update 1, June 30, 1980, Outer Continental Shelf Oil & Gas Activities in the Mid-Atlantic & Their Onshore Impacts: A Summary Report, November, 1979; US Geological Survey.

2. Personal communication, December 5, 1980, Charles R. Ham, Operations Division, New York OCS Office, Bureau of Land Management, US Department of the Interior.

An explanation of resource estimates, assumptions and methodologies used in generating the development scenarios presented in this chapter is contained in Appendix A.

In this chapter, assumed offshore development scenarios for the Mid-Atlantic and North Atlantic Regions are presented, followed by a discussion of potential onshore facility requirements and siting considerations.

A. Offshore Development Scenarios

At present, offshore activity in the Mid-Atlantic OCS Region is minimal. Two lease sales have occurred, but no commercially exploitable finds have been announced. At present, two exploratory rigs are operating, but discovery of resources in recoverable quantities is not anticipated. Based on the information presented in Appendix A, the following development scenario has been assumed.

Exploration will continue at the present level, with two rigs in operation, until Lease Sale 59, which is scheduled for December, 1981. Obtaining permits for exploratory drilling in tracts leased under Sale 59 will require approximately one year, so drilling will begin in late 1982. Lease Sale 76 will occur as scheduled in November, 1983, and the permitting process for exploratory drilling will require approximately one year. The assumed schedule of rigs operating in the Mid-Atlantic Region is shown below:

	1982	1983	1984	1985	1986	1987	1988	1989	1990
No. of Rigs Operating	6	9	10	10	12	11	8	4	2

The first find will occur during 1983 in lease area 56. The assumed schedule of finds is shown below:

Find A, 1983:	.091 billion bbls oil .09 trillion cf gas
Find B, 1984:	1.4 trillion cf gas
Find C, 1984:	.045 billion bbls oil .05 trillion cf gas
Find D, 1985:	1.18 trillion cf gas
Find E, 1985:	.173 billion bbls oil .17 trillion cf gas
Find F, 1985:	.164 billion bbls oil .16 trillion cf gas
Find G, 1986:	.057 billion bbls oil .06 trillion cf gas
Find H, 1987:	1.0 trillion cf gas

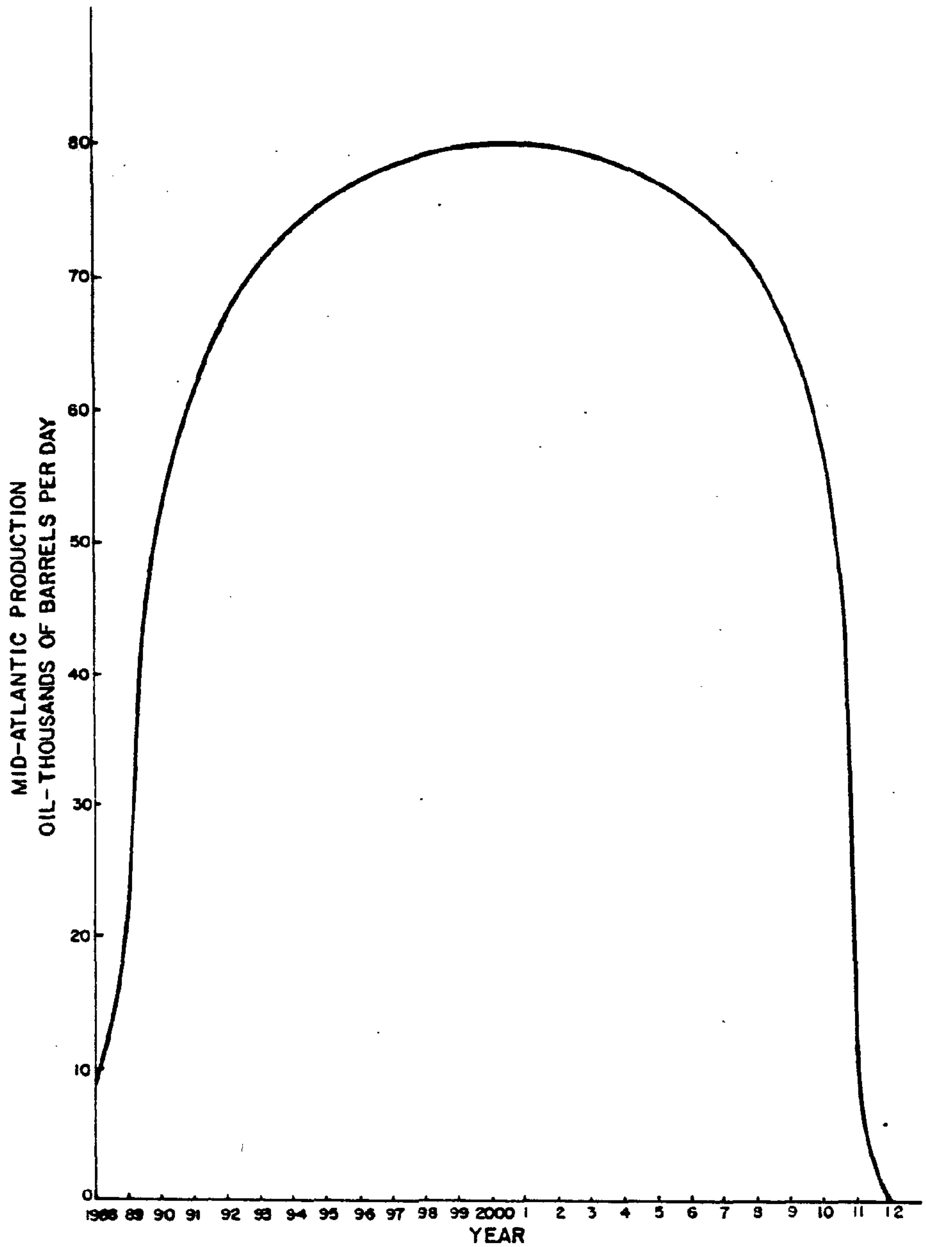
Exploration will continue through 1990, but no additional finds are anticipated, based on current resource estimates. Support for exploratory activity will come from the existing service base at Davisville, Rhode Island.

A total of 17 platforms will be installed, including three collection/metering/pumping stations. Platform installation will begin in 1985 and proceed according to the following schedule:

	1985	1986	1987	1988	1989
Number of platforms installed	1	3	8	3	2

Platform fabrication will occur outside the Mid-Atlantic/New England states, with support for platform installation coming from two small service bases located in the Mid-Atlantic states.

Production will begin in 1988 and continue through 2011, with a peak of 79 thousand barrels of oil and 807 million cubic feet of gas per day. Production levels for oil and gas are presented graphically in Figures 11 and 12. Support for development and production will involve approximately 50 vessels and 15 helicopters (approximately three vessels and one helicopter per platform). Approximately half the vessels and all of the helicopters will operate out of service bases in the Mid-Atlantic states, with the other vessels operating out of service bases in New England. Construction of permanent service bases will occur between 1984 and 1986.



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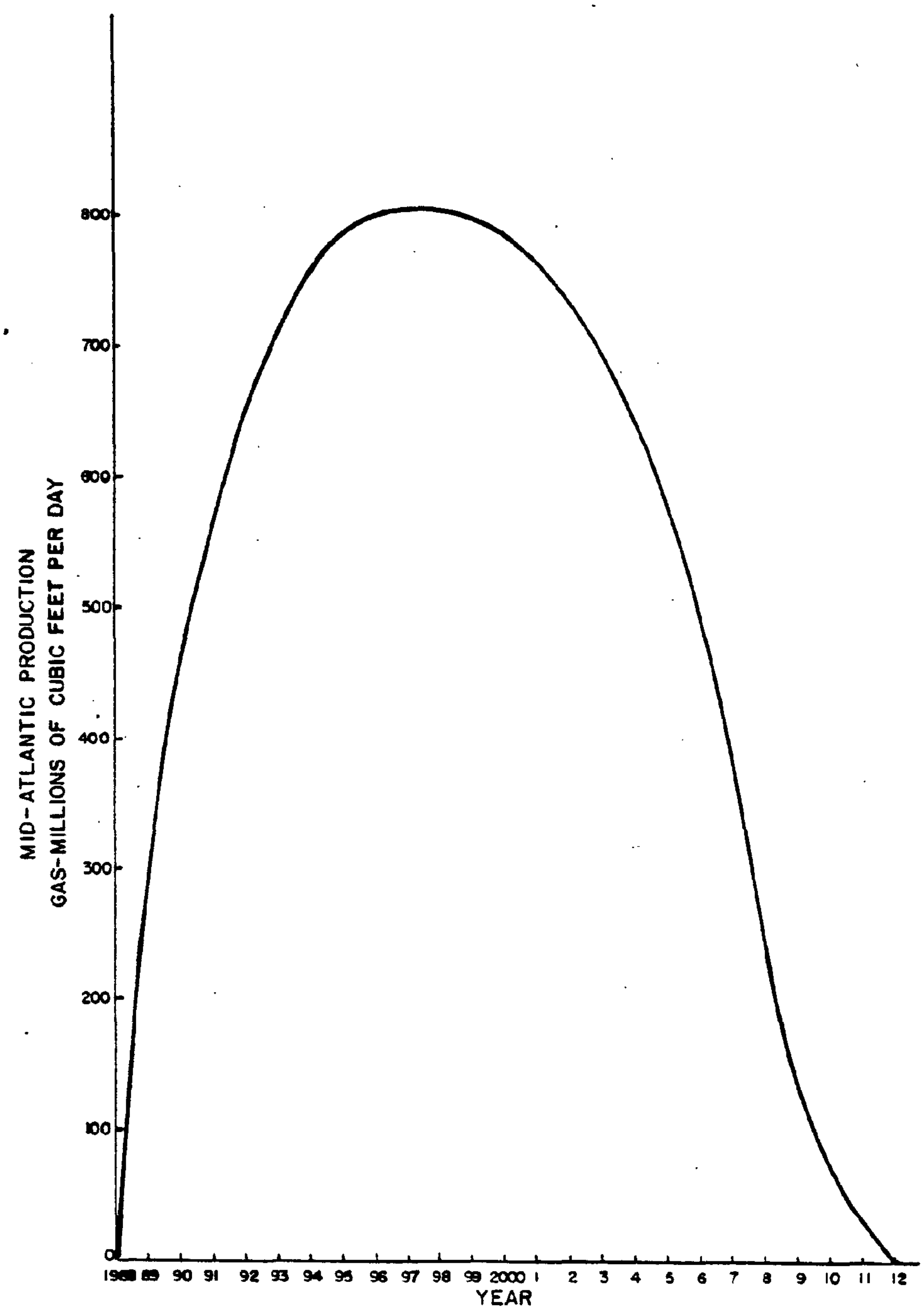

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Both oil and gas will be transported ashore in pipelines constructed between 1985 and 1989. Approximately 400 miles of pipeline will be constructed, with pipeline landfalls located in New Jersey. Pipeline construction will be supported from small service bases located in the Mid-Atlantic states. A pipe coating yard will also be located in the Mid-Atlantic states.

No exploratory drilling has occurred thus far in the North Atlantic OCS Region, but the permitting process is currently underway and drilling is expected to begin in 1981 in the tracts leased under Sale 42. Future lease sales in the North Atlantic Region are scheduled for October, 1982, (Lease Sale 52), and October, 1984, (Lease Sale 82). Based on the information presented in Appendix A, the following development scenario has been assumed.

Drilling in lease area 42 will begin in 1981. Approximately one year will be required after Sales 52 and 82 to obtain the required drilling permits. The assumed schedule of rigs operating in the North Atlantic Region is shown below:

	1981	1982	1983	1984	1985	1986	1987	1988	1989
Number of Rigs Operating	8	6	5	7	10	9	6	3	2

The first economically recoverable find will occur during 1983 in lease area 42. The assumed schedule of finds is shown below:

Find A, 1983:	.093 billion bbls oil .09 trillion cf gas
Find B, 1984:	.19 billion bbls oil .19 trillion cf gas
Find C, 1985:	1.42 trillion cf gas
Find D, 1986:	.073 billion bbls oil .08 trillion cf gas

Exploration will continue through 1989, but no additional finds are anticipated based on current resource estimates.

A total of ten (10) platforms will be installed, including a collection/storage platform for oil and a collection/metering/pumping station for gas. Platform installation will begin in 1986 and proceed according to to the following schedule:

	1986	1987	1988	1989
Number of platforms installed	2	3	4	1

Platform fabrication will occur outside the Mid-Atlantic/New England states, with support for platform installation coming from a small service base in New England.

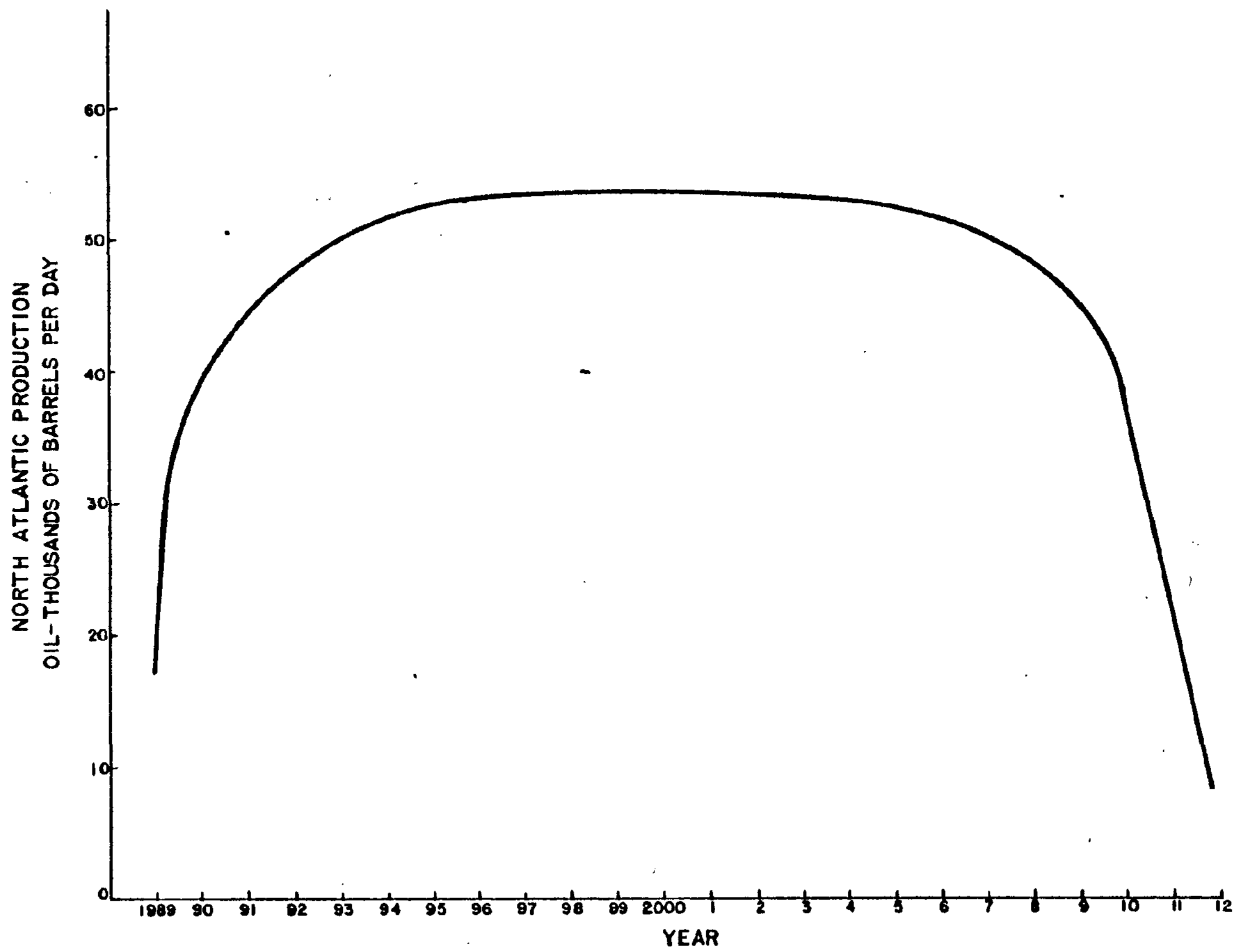
Production will begin in 1989 and continue through 2012, with a peak of 53 thousand barrels of oil and 344 million cubic feet of gas per day. Production levels for oil and gas are presented graphically in Figures 13 and 14. Support for development and production will involve approximately 25 vessels and 8 helicopters with support bases located in New England. Construction of permanent service bases will occur during 1985 and 1986.

Gas will be collected and transported ashore in pipelines constructed between 1987 and 1989. Approximately 200 miles of pipeline will be constructed with the landfall located in Rhode Island or Massachusetts, south of Cape Cod. Pipeline construction will be supported from a small service base in New England. A temporary pipe coating yard will also be constructed in New England. Oil will be collected through pipelines, stored offshore and transported by tanker.

B. <u>Onshore Facility Requirements and Siting Considerations</u>

Based on the offshore development scenarios presented above, the following onshore support facilities could be required in New England to support operations on the Baltimore Canyon and Georges Bank:

3 - 6	service bases
1 - 2	helicopter support bases
1	pipe coating yard
1	pipeline installation service base
1	platform installation service base
1	pipeline landfall and pumping station
1	gas processing plant



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FALL RIVER WATERFRONT STUDY	DATE FEB.1981	FIG. NO. 13

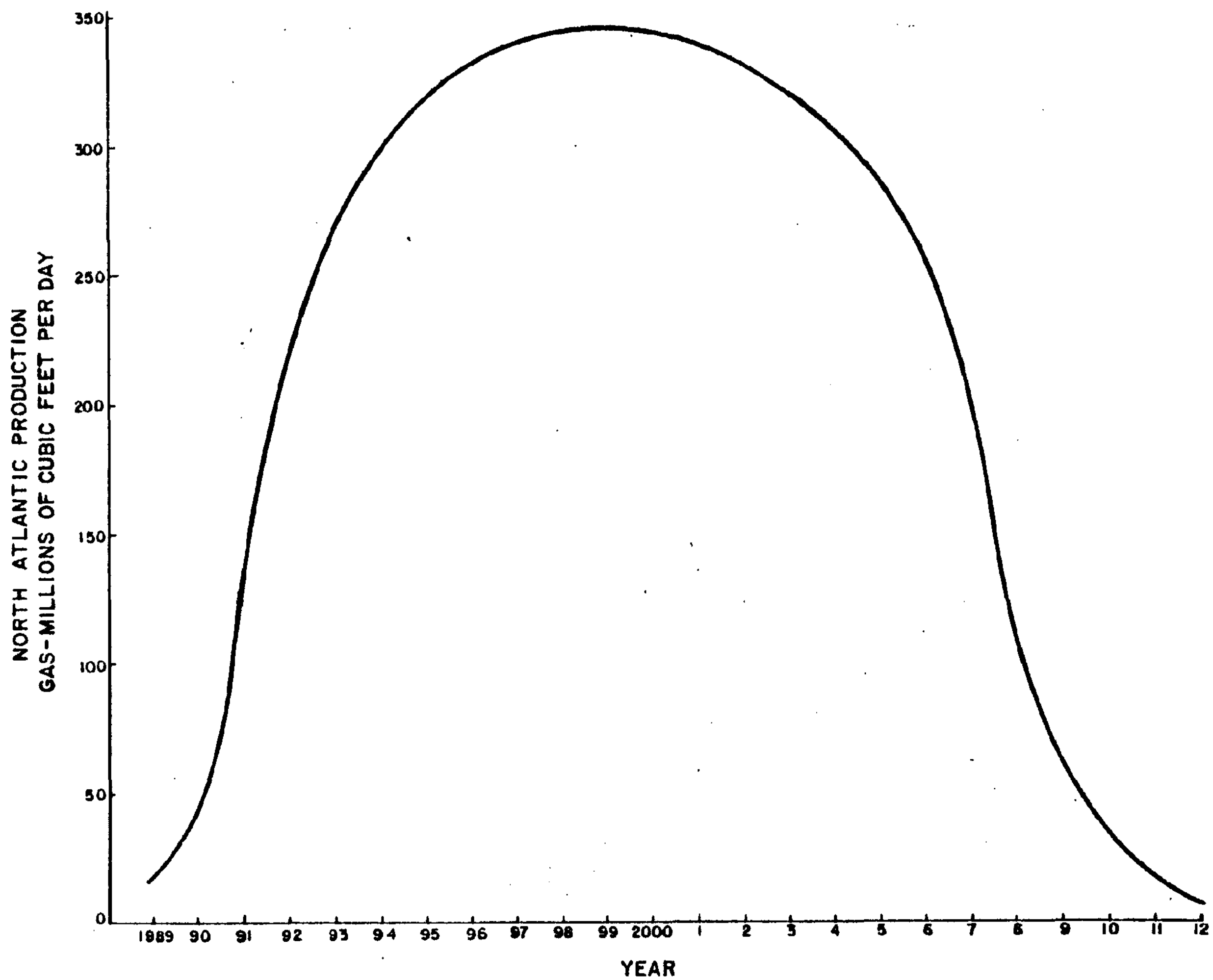

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FIG. NO. 14

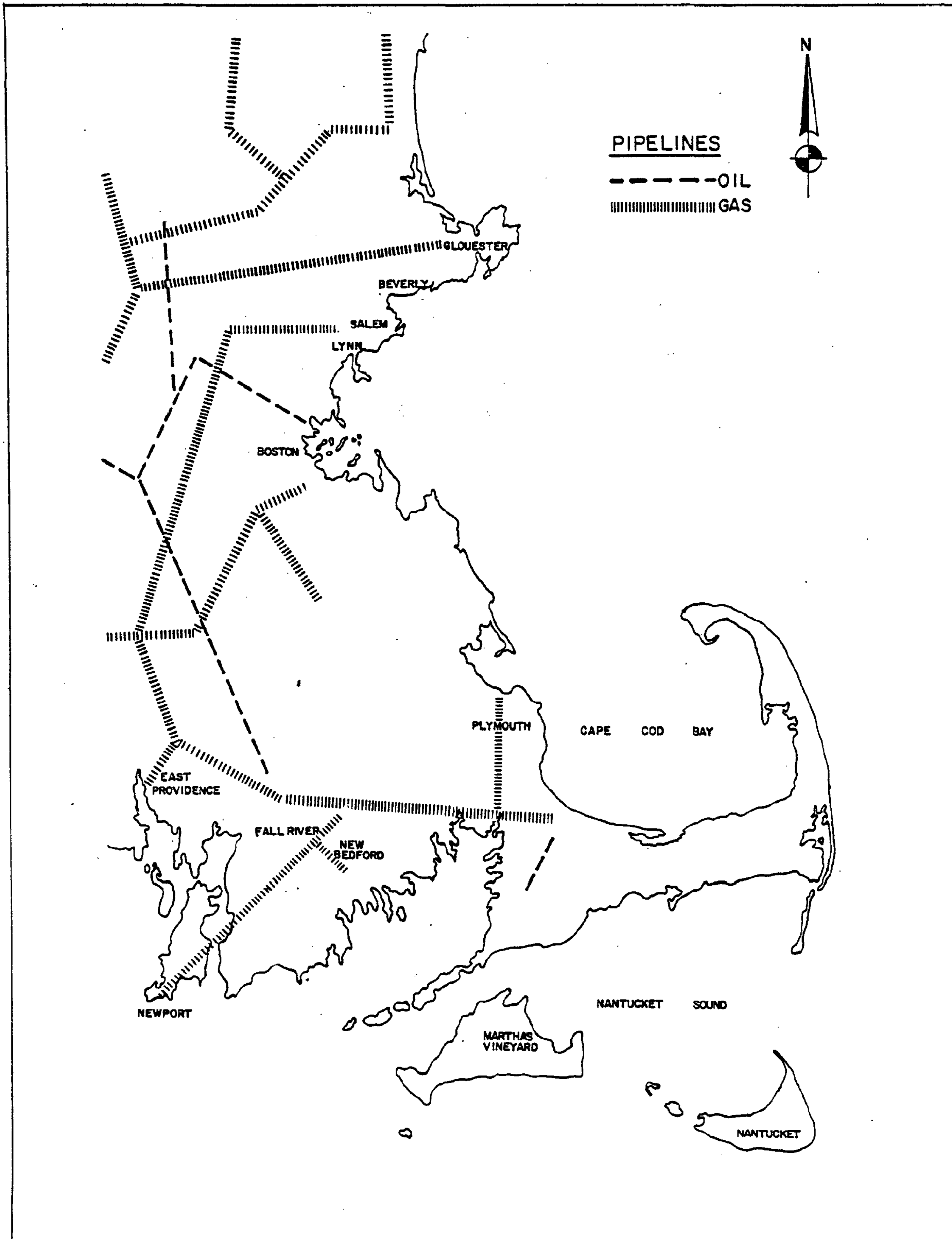
It appears unlikely that a refinery will be constructed in response to OCS finds, but if one is constructed as a result of market factors (as is being proposed for the Fall River-Freetown area), a marine terminal and tank farm would also be required. If a refinery is not constructed independent of offshore discoveries, crude oil from Georges Bank would most likely be tankered to existing refineries in the Mid-Atlantic states in order to avoid rehandling and construction of additional terminal/tank farm facilities.

The number of service bases reflects the berthing facilities required to support 50 vessels (25 to support operations on the Baltimore Canyon and 25 to support operations on Georges Bank). Assuming that vessels can be rafted (berthed more than one abreast), with a practical level of two vessels per berth (more vessels could be rafted at a berth but this would reduce the efficiency of the berth), 25 berths would be required. Existing facilities at Davisville could accommodate approximately 35 - 40 vessels, leaving 10 to 15 vessels requiring support elsewhere. In addition, based on previous OCS development patterns and discussions with industry representatives, it has been assumed that more than one service base is desirable. The upper limit of service base requirements is based on the potential use of Davisville by other activities, both OCS and non-OCS related, which could reduce the amount of berthing space available. Davisville is the most likely site in New

England for location of a pipe coating yard, due to the availability of large land area and excellent rail connection. Use of a portion of it for that purpose would reduce the amount of area and frontage space available for other support operations. In addition, the potential exists for development of non-OCS related commercial and industrial activities at Davisville, also reducing the amount of area and frontage space available for OCS support. It has been assumed that a minimum of 10 berths would be available for service base operations at Davisville, leaving fifteen berths required elsewhere in New England. Since no facilities comparable to Davisville are available and few potential development sites of that size exist, it has been assumed that no other service bases will provide more than five berths and that two berths will be the minimum number justifying development of a service base. Using an average of three berths per service base, therefore, five service bases would be required in addition to Davisville. Potential locations for these service bases include Gloucester, Beverly, Salem, Lynn, Boston, New Bedford and Fall River, Massachusetts; and Aquidneck Island, Point Judith and Tiverton, Rhode Island.

At least one and possibly two helicopter support bases will be required; these will probably be located on Cape Cod in order to minimize travel time to offshore operations. The helicopters will operate between the service bases and the platforms and will make trips to Logan Airport to transport workers leaving or returning; the helicopters will be housed and maintained at the helicopter support base(s).

As mentioned previously, Davisville is the most likely location for a pipe coating yard, for a variety of reasons. The most likely sites for the pipeline landfall appear to be in Newport, Rhode Island, and Fall River and New Bedford, Massachusetts. These areas are closest to the potential resource locations, based on areas of high interest, and have existing commercial transmission lines, as shown in Figure 15. Cape Cod was excluded from consideration because of the potential for delay in obtaining permits due to environmental concerns. Based on potential locations of the pipe coating yard and pipeline landfall, Davisville, Portsmouth, Middletown, Tiverton, Newport, Fall River, and New Bedford appear to be the most likely sites for the pipeline installation service base. These areas, as well as the potential service base locations, also appear to be the most likely sites for location of the platform installation service base. Location of the gas processing plant is dependent on the pipeline route, as well as availability of the large quantities of water required. The gas processing plant need not, and probably will not, be located on a waterfront site. Westport, Dartmouth, New Bedford and Fall River in Massachusetts, and Aquidneck Island in Rhode Island appear to be the most likely locations for this facility.



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A number of ancillary industries will be required in New England to support offshore operations. It appears likely that the location of these industries will be closely related to the location of service bases. Mud and cement companies may operate out of their own berthing areas, but other ancillary industries will probably utilize service bases or other waterfront facilities for vessel access to offshore activities. Ancillary industries may locate near a service base in order to utilize its berths or the location of a number of ancillary industries operating from non-OCS related berthing areas may result in location of a service base there. In either case, the location of service bases and ancillary industries is interdependent, since one cannot operate without the other.

Several service companies, including mud and cement companies and tool and equipment companies, have already established operations at Davisville and it appears likely that others will do so, particularly during the exploratory phase of OCS activities. The number of firms invloved in each type of ancillary industry will vary, depending on the nature of the industry and the ownership patterns in projected finds. Should two or three oil companies account for a large percentage of the finds, the numbers of firms involved in ancillary industries will be limited, since an oil or drilling company is likely to use only one mud, cement, or tool supplier; successful exploration by a greater number of offshore operators is likely to increase the number of firms involved in supplying services, equipment, supplies and personnel.

V. POTENTIAL DEVELOPMENT IN FALL RIVER

The sites previously identified as being potential locations for development of OCS support/coastal energy facilities and the types of OCS/coastal energy activities that could potentially locate at each site are discussed in the following sections. The activities and sites discussed should not be considered to be recommendations or suggestions, but rather evaluations of potential development. Actual development will depend on a complex series of factors, including the location and size of finds in the North and Mid-Atlantic; the national and international energy, economic, and political situations; technological developments; and chance. It is unlikely that all of the development discussed below will occur in Fall River; however, the energy industry is highly competitive, so it is likely that Fall River will be considered by potential developers of these activities.

Site A is shown on Figure 16. This site consists of several plots of approximately 25 acres with 1,400 feet of waterfront. The most likely use of this site, based on its size and location, would be as a service base. It appears likely that temporary and pipeline/platform installation support bases will locate on small sites with berthing facilities available. Several port areas contain existing berthing facilities which could be used to satisfy this demand, so it does not appear that the cost of development of berthing facilities at this site will be justified for a temporary or installation service base. Support operations involved with exploratory operations will probably be satisfied by firms cur-

FIGURE 16

rently located at Davisville. If additional mud, cement, drilling tool, etc., companies do establish local operations during exploration, they should be able to obtain space at under-utilized facilities.

Permanent service bases will require tracts of vacant or underutilized land that are relatively large and have waterfront access; these are not readily available in New England, so it appears that the capital improvements necessary to develop this site may be justified. It does not appear that this site is a likely location for a pipeline landfall or a marine terminal because of the problems associated with construction of an onshore pipeline route to connect to existing transmission lines.

The railroad tracks separate the waterfront from most of the land area, but the tracks are at approximately the same elevation as adjacent land and do not appear to be a major obstacle to development of this site.

Based on the amount of waterfront and back-up area available, a service base at this site could support three to four platforms, requiring approximately 1,100 feet of berthing space, three acres for helipads, three acres for open storage, two acres for covered storage, and 10,000 square feet for administration, communication, and maintenance facilities. Additional space would be necessary for parking, circulation, and a buffer zone to mitigate impacts on adjacent areas.

A service base at this site could provide berthing for 10 to 12 vessels, which would primarily be supply boats. Because of the distance to offshore operations, helicopters are likely to be the primary method of transporting crew members, so crew boats will only be used when large numbers of personnel must be transported. The base would employ approximately 200 people, with wages averaging about $20,000 per worker, for an annual payroll of approximately $4 million. Capital investment requirements would be approximately $5 million.

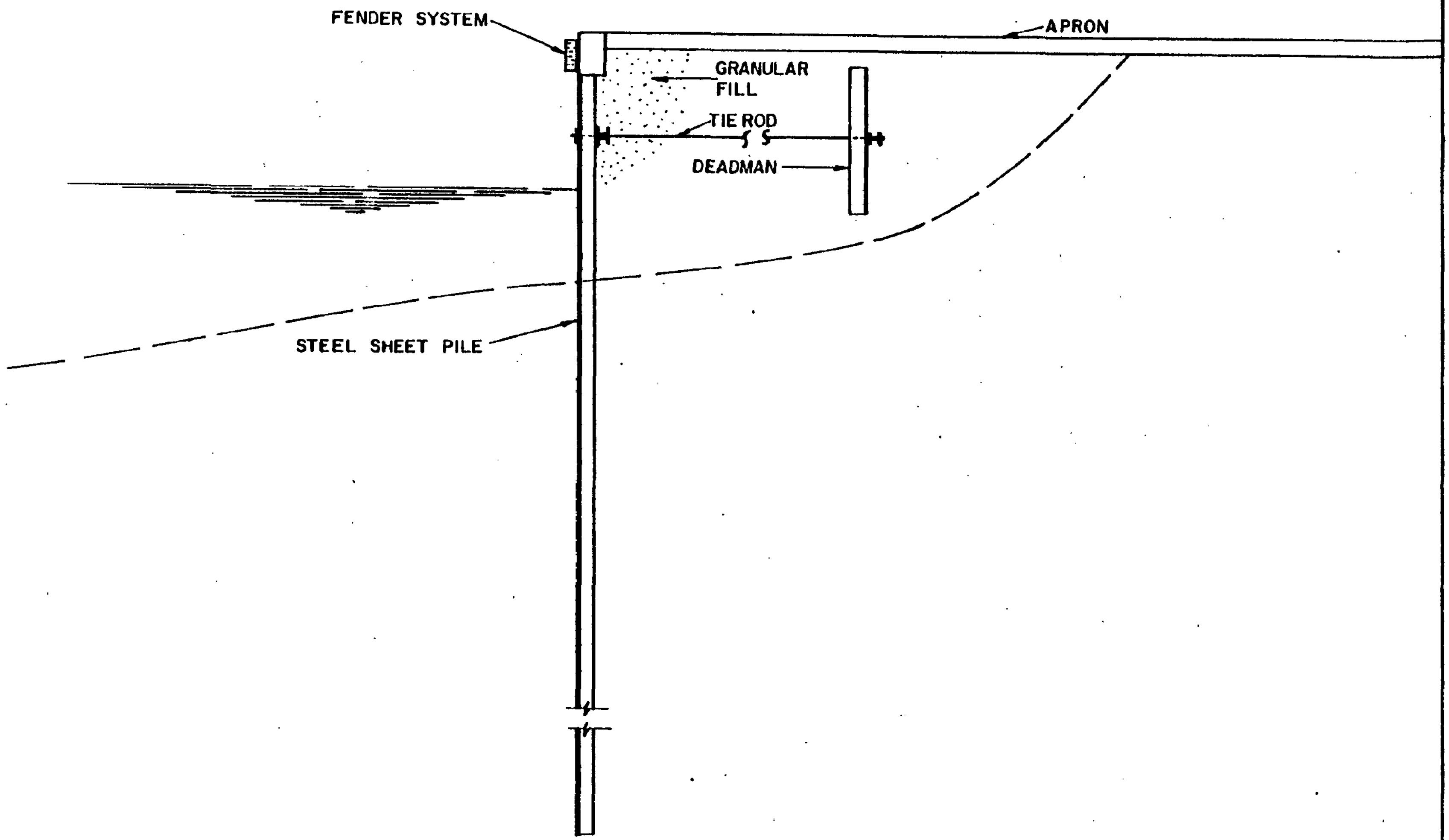
It appears likely that development of a service base at this site would encourage the location of ancillary industries in the Fall River area. These industries could locate on inland sites, some possibly utilizing existing available space in mill buildings. These industries would involve minimal impacts and provide economic benefits in the form of rent or capital investment, wages, and local purchase of supplies and services.

Throughput at a service base of this size would include approximately 40,000 tons of material, 30 million gallons of fresh water, and 185,000 barrels of fuel per year. These quantities would decrease significantly during the production phase of activity, with fuel (60,000 to 80,000 barrels per year), food, and water being the major commodities handled.

Development requirements will include clearing, grading and paving of the site; construction of covered storage, administration, communications, and maintenance facilities; dredging of an access channel and construction and dredging of berths; and construction of a rail spur. A depth of at least 15 feet would be required in the access channel and along the face of the earth. The berths could be provided by means of a vertical retaining wall and an apron, or by means of a sloped retaining wall and pile-supported pier. Examples of these construction alternatives are shown in Figures 17 and 18. The bulkheading option provides a marginal wharf directly adjacent to the apron, while the pile-supported pier requires some type of access from the apron to the pier. With proper design, however, the use of a sloped, armored retaining wall can be less expensive and involve minimal operational inconvenience.

The major impacts of development of this site would include increased volumes of runoff, some of which may be contaminated, due to site alteration; increased turbidity and displacement of natural habitat due to dredging and construction of berths; air emissions due to storage and handling of fuel, operation of vehicles, vessels and equipment, and storage and handling of dry mud and cement; increased noise levels due to the operation of vehicles and equipment; and increased volumes of wastewater and solid wastes, some hazardous, generated by offshore operations and the service base itself.

Increased volumes of runoff will result from clearing and paving of the site, and some of the runoff could be contaminated by



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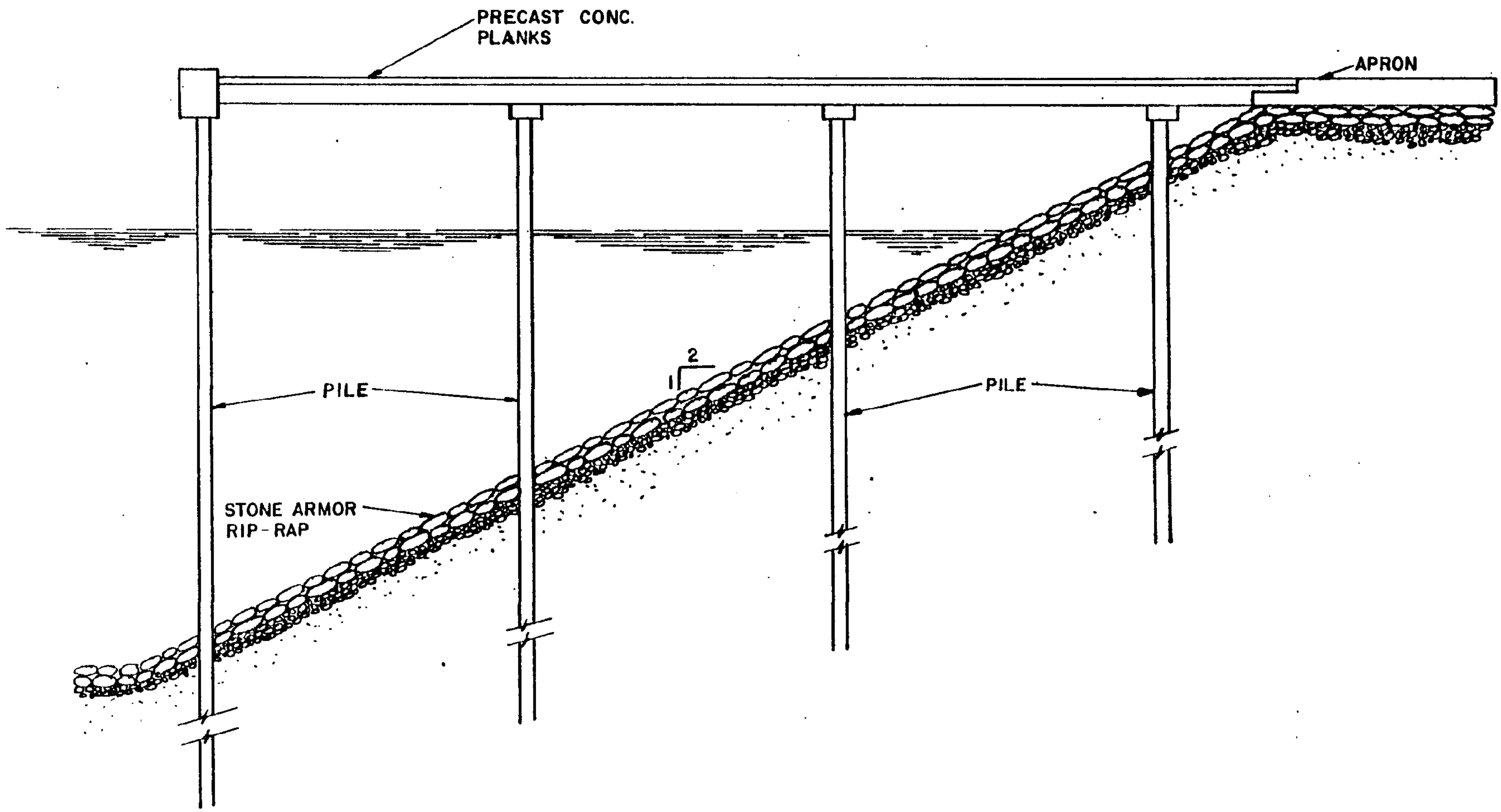


MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB. 1981	FIG. NO. 18

spills of hazardous materials. Areas where hazardous materials are stored or handled should be diked, and the runoff collected for treatment and disposal. A drainage plan should be developed to control and collect the flow of runoff from the site.

Dredging will involve increases in turbidity and displacement of bottom habitat, but these impacts are generally accepted to be temporary. The major issue connected with dredging will be disposal of dredge spoils, which is already a major concern in Narragansett Bay as well as most other New England ports. Maintenance dredging requirements may be increased due to the use by OCS support vessels of bow-thrusters, which can cause scouring and siltation. Maintenance dredging and the use of bow-thrusters can also increase the suspension of pollutants contained in sediments or generated by increased industrial activity at the site. Dredging may require special techniques and elaborate precautions in spoil containment and disposal to prevent contamination of surface or ground water or impacts on local air quality resulting from evaporation. Construction of berths, using either a sloped or vertical retaining wall, will involve displacement of natural habitat.

Based on a four week fuel storage capacity, approximately three to four pounds of hydrocarbon emissions would be released from stored fuel each day. Hydrocarbon emissions will also occur as the result of transfer of fuel and operation of vehicles, vessels, helicopters and equipment. Dust emissions will result from storage and handling of dry mud and cement. Several methods exist to minimize air emissions; with regard to hydrocarbons, up to 95 percent of the emissions can be eliminated by maintenance of hoses, seals and mechanical equipment and proper design of storage tanks. Care in the maintenance and operation of mud/cement tranfer systems can control dust emissions from those operations.

Noise levels in the area will increase as a result of construction and base operation. Noise will be generated from transportation equipment, power tools, air compressors and compressed air tools, cranes, and pumps; since on-site operations will continue on a 24-hour basis, noise will be generated around the clock. Noise levels of 90 to 100 dBA will be generated from much of the equipment, but these can be abated by the use of mufflers and sound absorbers on equipment and combustion engines, and provision of a buffer zone around the site. The buffer zone will also mitigate adverse aesthetic impacts.

Wastewater generated at the site will consist of sewage, bilge water, ballast water, and cooling water. Sewage will be generated from the vessels and onshore personnel at the rate of approximately 6,000 gallons per day. Bilge water collects in the lower portion of the boats and often contains oil, grease, and metallic compounds from machinery leaks. Vessels operating from the service base would generate approximately 1,500 gallons of bilge water per day. Ballast water is used in supply and crew boats to replace offloaded cargo or improve handling of the vessel. Vessels will probably discharge ballast water at the service base after returning from delivering supplies or personnel to the platforms. Ballast water often has a high biological oxygen demand (BOD) and high concentrates of fecal bacteria and heavy metals. Vessels based at the service base will generate approximately 25,000 gallons of ballast water per day. Cooling water circulates through vessels while their engines are in operation, and is recirculated or discharged, but quantities of discharge are negligible. Bilge, ballast and cooling water can be discharged into coastal waters or into tanks at the service base, where it can be treated and disposed of or reused. Federal regulations allow the direct discharge of bilge, ballast, and cooling water from normally functioning vessels; onshore disposal may be desirable in some cases but eventually involves the disposal of large quantities of contaminated material, with resultant environmental impacts that could be more serious than direct at-sea discharge.

Solid wastes at the service base will include those generated by offshore operations and those generated by the service base itself. The major wastes generated by offshore operations are drilling wastes, galley garbage, oily sludges, lubrication oils, packaging material, scrap material, and human wastes. Drilling wastes often contain hazardous materials which must be returned to shore for disposal. Approximately 800,000 cubic feet of solid waste will be generated by offshore operations each year during drilling operations, some of which can be disposed of at sea, but some must be returned to the service base for disposal. Approximately 100,000 pounds of solid waste will be generated at the service base per year. If materials are disposed of according to existing regulations, no adverse environmental impacts should occur, but hazardous material must be disposed of at a special landfill to insure that ground or surface waters are not contaminated and evaporation does not affect air quality.

The permitting process for development of this site would involve state and federal agencies, as well as the City of Fall River. As a designated port area, development of onshore facilities at this site would be in accordance with the Massachusetts Coastal Zone Management (CZM) Program, unless development is opposed by the City of Fall River through the local conservation commission. Construction on underwater land, including bulkheading and dredging, would still be presumed to involve significant impacts, however. Dredging and filling would require the issuance of a Water Quality Certificate from the Massachusetts Division of Water Pollution Control and a permit from the U.S. Army Corps of Engineers and the Environmental Protection Agency (EPA). Ocean disposal of dredge spoils would also require approval from the Corps and EPA; onshore disposal would require approval from EPA and the Massachusetts Department of Environmental Quality Engineering. Construction below the mean high water line would require a Tidelands License from the Massachusetts Division of Waterways and a permit from the Corps of Engineers.

Approval for use of this site as a coastal energy facility would be required from the Massachusetts Energy Facilities Siting Council. Discharge of pollutants into the air and water would be regulated by the Massachusetts Divisions of Air Quality Control and Water Pollution Control, respectively. Fall River is a non-attainment area for Total Suspended Particulates so approval of discharges into the air would require the use of effective control technology and an offsetting reduction in emissions from an existing source. The Taunton River is classified SB, meaning that it is to be used for protection and propagation of fish, other aquatic life and wildlife; for primary and secondary contact recreation; and for shellfish harvesting. Although it does not currently meet the standards of the SB classification, progress are in progress to meet the standards by 1983. Discharges into the River which are not consistent with SB standards or which would interfere with meeting those standards would require a waiver or change of classification.

Disposal of solid waste or hazardous or contaminated material would be subject to local, state and federal regulations. Transfer of fuel to OCS support vessels would require approval from the U.S. Coast Guard. Since state permits and licenses are involved, an Environmental Notification Form would be required; since federal permits are required, development would be subject to review by the Massachusetts Coastal Zone Management (CZM) Office for consistency with state CZM Program policies.

The permitting process should insure that adequate mitigation measures are implemented. These should include a buffer zone around the site; incorporation of a diking/collection/containment system in facility design; preparation of acceptable plans for disposal of solid waste, contaminated wastewater and runoff, and dredge spoil; use of the necessary noise and emission control technology; and establishment of adequate maintenance and monitoring programs.

Overall, it appears that the impacts of construction and operation of a service base can be adequately mitigated through careful planning and design of facilities and application of existing regulations. This site was previously used for industrial activities, so development would not involve a pristine site. Impacts in the form of water demand and disposal of contaminated material appear to be manageable, as long as development is closely monitored.

Site B is shown on Figure 19 and is the site of Sanchez Marine. There is approximately 1900 feet of berthing space at this site, with additional waterfront that could be developed for berthing space. The most likely potential uses of this site appear to be as a temporary service base, pipeline installation service base, platform installation service base, or a transfer point for ancillary industries that do not require the waterborne movement of large pieces of equipment or volumes of material. Location of ancillary industries in Fall River will be dependent on the exist-

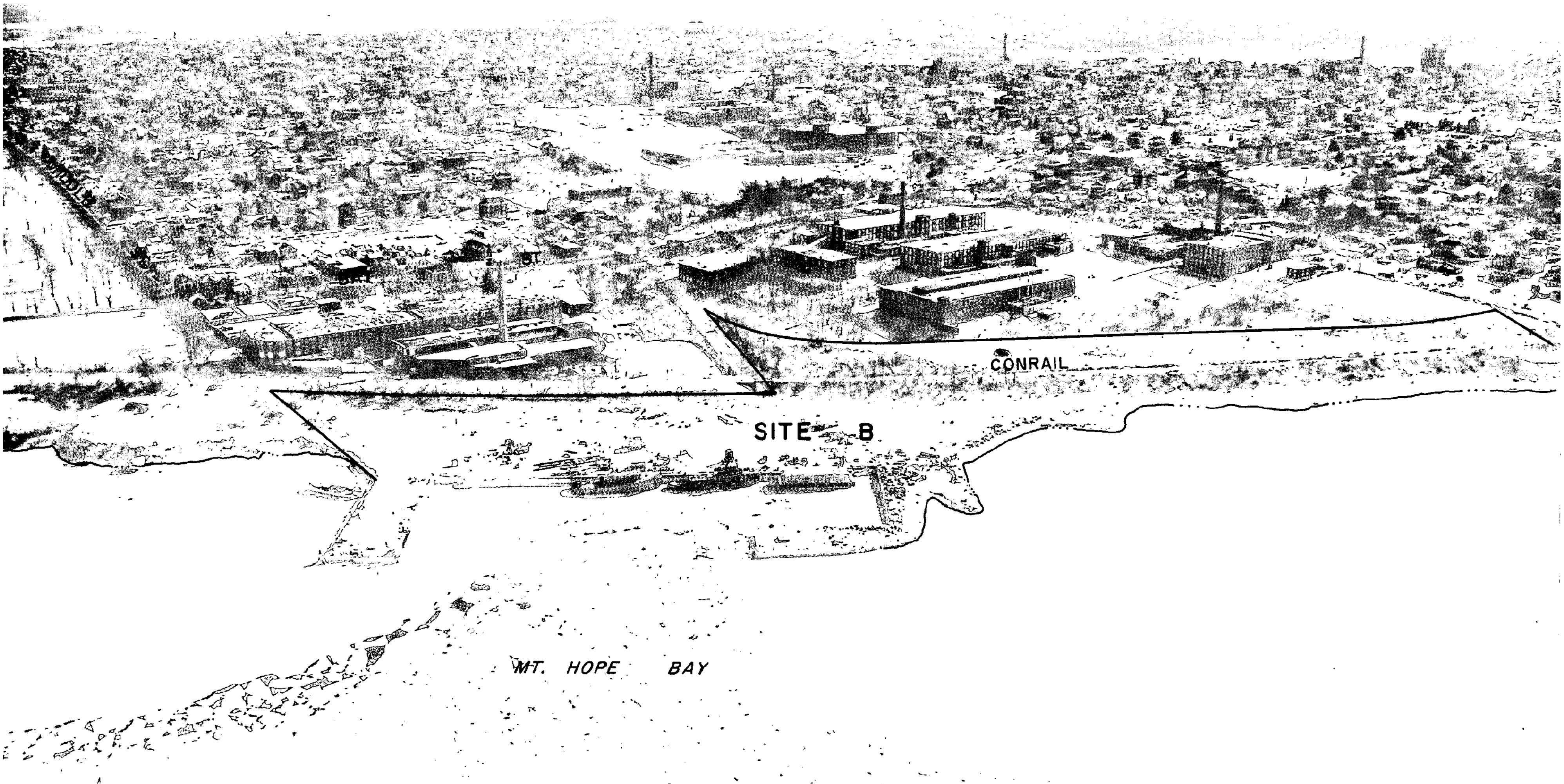


FIGURE 19

ence of facilities providing waterfront access. Approximately seven acres of land is included in this site, not enough for a permanent service base, but some additional land, currently vacant, is located on the other side of the railroad tracks. The railroad tracks are approximately 10 feet above adjacent land at this point, forming an effective barrier to development of marine related facilities. Land on the shoreward side of the tracks could, however, be used for storage, but the only land access to the site is via an underpass beneath the tracks, limiting the operational efficiency of development on both sides of the railroad embankment. The land available on the seaward side of the tracks appears to be adequate to support a smaller service base or transfer point, however.

Development requirements at this site would be minimal. Building requirements could be satisfied by the use of trailers and/or the construction of simple frame structures. A helipad and a rail spur could be constructed if necessary.

Assuming that some nearby non-waterfront land can be used for open storage, a temporary or installation service base on this site could support two exploratory drilling rigs, a pipeline installation, or the installation of approximately four platforms per year. All of these potential uses would involve approximately twenty five to forty employees, with annual wages averaging approximately $20,000 each for a total payroll of $500,000 to $800,000 per year.

The major impacts of development of this site would result from the increase in industrial activity in the area and the fuel demands of vessels and helicopters. Fuel demands would range from approximately 5000 to 7500 barrels per month. It is not anticipated that fuel would be stored at this site, but rather obtained at existing fueling facilities nearby. Air emissions as a result of increased fuel storage and handling in the area would be approximately one pound per day, although this could be reduced through careful planning and design of storage facilities and mechanical equipment, use of control techniques, and maintenance of valves, seals, and mechanical equipment. Dust emissions would result from the transfer of dry mud or cement, but these could be controlled by adequate maintenance of storage and handling equipment.

Wastewater and solid waste would be generated by offshore operations, vessels using the base, and onshore activities. Approximately 16,000 gallons of bilge and ballast water would be generated each day, as well as approximately 6500 gallons of sewage. Solid waste from exploratory rigs would include drilling wastes, oily sludges, galley garbage and packing materials. Approximately 7000 cubic yards of solid wastes would be generated each year by offshore operations, some of which would have to be returned to the base for disposal. Solid waste from pipe laying and platform installation operations would involve mainly galley garbage, packaging materials, and human waste. Fresh water requirements for a temporary service base would be approximately 10 million gallons per year.

No permits would be required for dredging or waterfront construction at this site, since none will be required. This site has been designated as a port area by the Massachusetts Coastal Zone Management (CZM) Program, but development would still require the filing of a Notice of Intent and a public hearing. Use as an OCS support facility would require the approval of the Massachusetts Energy Facilities Siting Council. Discharge of pollutants into the air and water would require approval from the Environmental Protection Agency and the Massachusetts Divisions of Air Qaulity Control and Water Pollution Control, respectively. Increased noise levels would be subject to review under local, state and federal regulations. Disposal of solid and hazardous waste would also be subject to local, state and federal regulations. Approvals should be contingent on the preparation of acceptable plans for disposal of solid waste, contaminated wastewater and runoff; the use of noise and emission control technology; and establishment of adequate maintenance and monitoring programs for operation of the facility.

It appears that the impacts of development of this site are incremental and manageable. Use of the site will depend on an early entry into the OCS industry, either through development of the site by local interests, such as the owner, or attraction of OCS-related activities interested in establishing operations in New England. The existence of berthing facilities at this site is an advantage, but the limited size reduces the number of potential OCS-related uses. Development of this site as a temporary service base or an informal transfer point would be likely to result in the location of various ancillary industries in Fall River, as with site A.

Site C, the former Pennsylvania Central railroad yard, is shown in Figure 20. It contains approximately four acres. This site does not appear to be a likely location for OCS support facilities, but interest has been expressed in the use of this site for a coal unloading facility, in connection with the coal plant that has been proposed for Fall River. Increased rail traffic, air emissions from handling and storage of coal, and increased and contaminated runoff could cause significant impacts, unless mitigation is implemented. Discharge of contaminants into the air and water would be subject to compliance with federal and state air and water quality standards. Increased noise levels would be subject to local, state and federal standards. Mitigation measures should include diking and containment to prevent contaminated runoff from intruding into ground or surface water; development of a program to minimize dust emissions; and careful monitoring of compliance with relevant air, water, and noise regulations.

The method of transporting the coal from the offloading site to the plant is not known at this time; choice of a transport method and route from this site to the plant site could have very significant impacts, however, and should be subject to careful scru-

FIGURE 20

tiny before the permitting process is begun. It appears that approval would be required from the City of Fall River, state and federal energy departments, the U.S. Interstate Commerce Commission, Environmental Protection Agency, and the Department of Transportation; the Massachusetts Energy Facilities Siting Council, and Departments of Environmental Quality Engineering and Public Utilities, depending on the onshore transport method used. If state permits or licenses are required, the filing of an Environmental Notification Form would also be necessary. If federal permits are involved, development would be subject to review by the Massachusetts Coastal Zone Management (CZM) Office for consistency with state CZM Program policies.

Sites D and E are shown in Figure 21. These two areas contain approximately 15 acres on both sides of the railroad tracks. Site E is located west of the tracks, while site D, the larger of the two, is located east of the tracks, which also separate it from a narrow strip of waterfront land. These sites are adjacent to the landfall of transmission lines from the Montaup Electric generating plant. The upper turning basin and the northern channel limit of the Taunton River are both just south of these sites.

The size and location of these sites probably dictate that the most likely potential uses would be as a pipeline landfall or, if a refinery is constructed nearby in response to market demand, a marine terminal. It is unlikely that a permanent service base

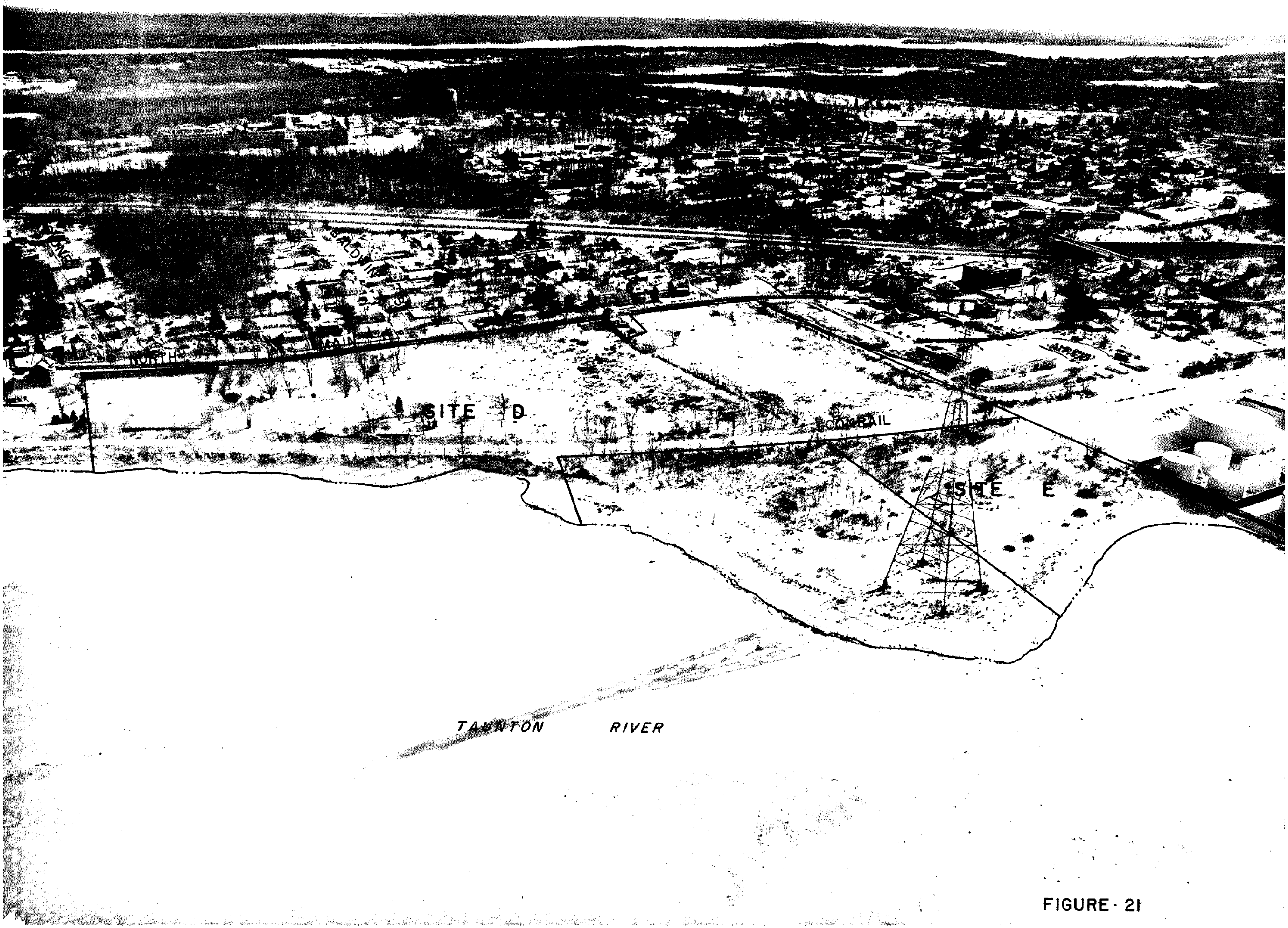
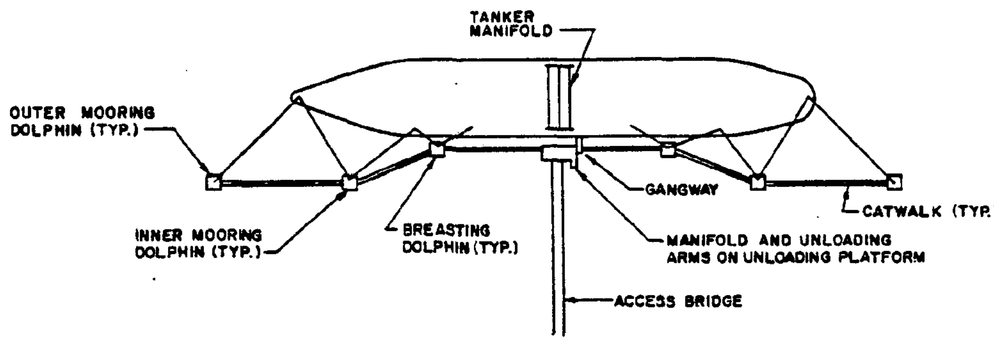


FIGURE · 21

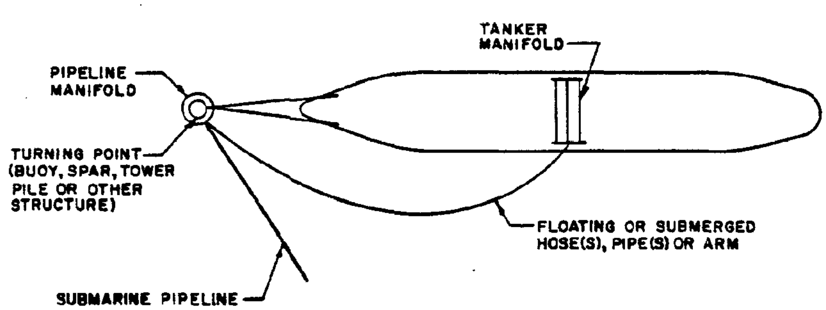
would be constructed at this site due to the lack of available land and the high cost of constructing a marginal wharf. However, the site is suitable for a pipeline landfall since that would not require berthing space and it is also suitable for a marine terminal since development costs could be minimized by the use of an offshore pier or floating. Figure 22 illustrates the concepts of these berthing altenatives.

The only employment connected with construction of a pipeline landfall at the site would be during the construction phase. However, it appears likely that a pumping station and processing plant would be constructed somewhere in Fall River if a pipeline landfalls here. A pumping station would employ approximately 15 people with annual wages of approximately $300,000, and involve capital investment of $3 to $5 million. A gas processing plant would employ approximately 50 people, with annual wages of approximately $1 million, and capital investment of $50 to $100. A marine terminal/tank farm would employ approximately 65 workers, with an annual payroll of approximately $1.3 million, and a capital investment of $25 million.

If these sites serve as a pipeline landfall, a pumping station and a gas processing plant would likely be constructed nearby. Existing easements extend north along the railroad tracks and west to the Fall River/Freetown border, crossing one of the sites identified in a previous study as a potential refinery site, as well as an Algonquin Gas Company transmission line easement



SEA ISLAND PIER



FLOATING MOORING

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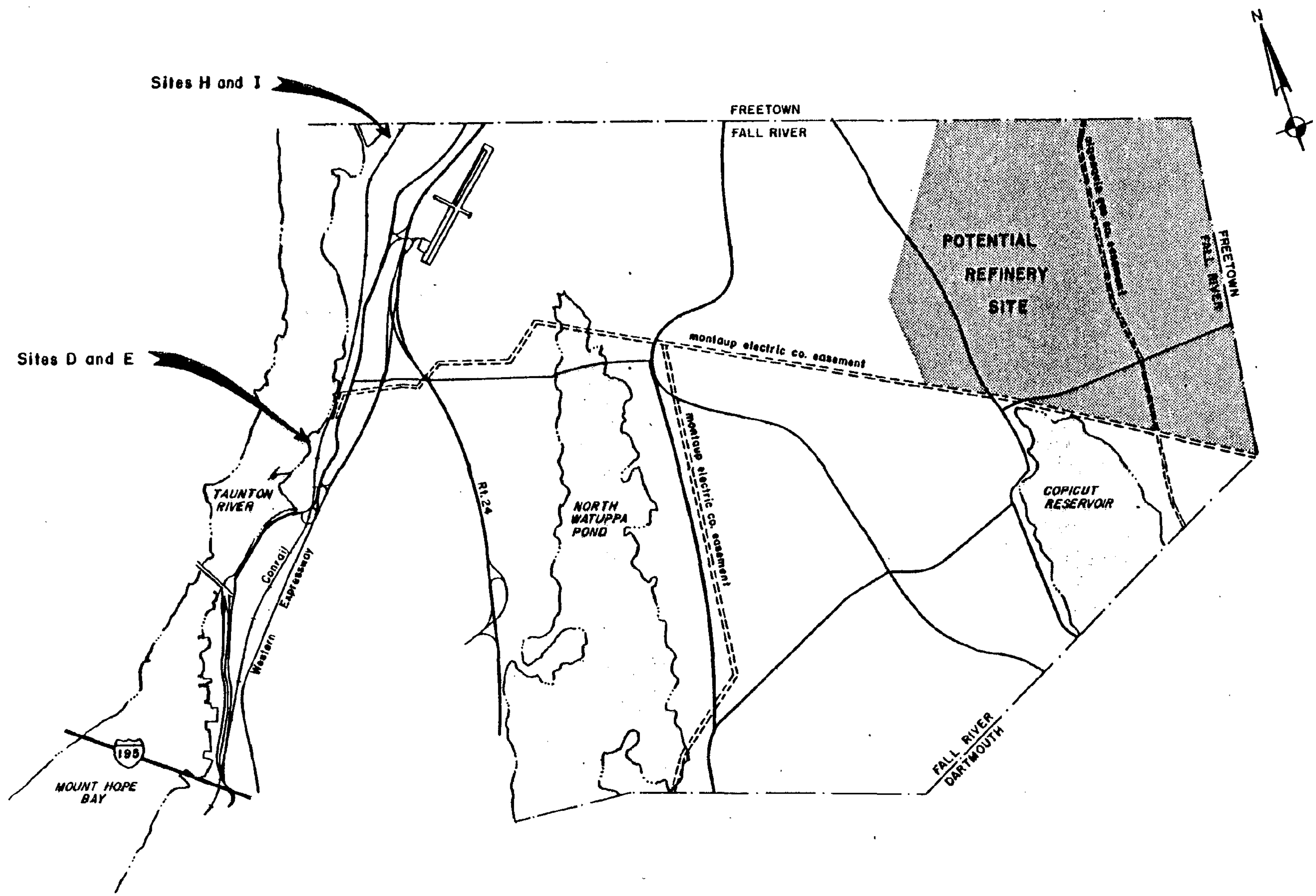
(see Figure 23). These existing easements would minimize the problem of an onshore pipeline route. A pipeline landfall would require minimal land area, mainly just a 50 to 100 foot right of way. It does not appear that adequate land is available in sites D and E to locate a pumping station there.

Impacts of a landfall would include temporary turbidity and disruption of bottom habitat during construction. Recent data indicates that these impacts are short-lived, although disturbance of bottom material in a river adjacent to a heavily populated, industrialized area such as Fall River may have greater impacts due to pollution and/or contamination of bottom sediments. The possibility of a gas leak is a potential impact of operation of a pipeline; however, technological developments in pipe coating, welding, and laying techniques have reduced the danger of pipeline leaks, and the use of pressure control and monitoring valves has reduced the consequences of a leak. If these sites are used for a landfall, chronic gas leaks from the pipeline will probably occur and could impact adjacent environmentally sensitive areas, but the number of leaks and their consequences can be minimized by careful maintenance and monitoring programs.

If a refinery is constructed in the Fall River area independently of OCS activities, a marine terminal/tank farm could be developed on these sites, with crude oil transported to the refinery in pipelines from surge tanks located on the site. Based on the



MAGUIRE Architects • Engineers • Planners	FALL RIVER WATERFRONT STUDY	DATE FEB., 1981	FIG. NO. 23

size of the site, a tank farm of approximately one million barrels could be constructed on this site, with the tanks occupying approximately five acres. Additional land is necessary for control and processing equipment, pumping stations, ballast storage tanks and treatment facilities, fire fighting equipment, and a buffer zone. Potential impacts of development of this site for a marine terminal/tank farm include increased and contaminated runoff; increased air emissions; degradation of water quality in the Taunton River; reduced aesthetic quality of the area; increased noise levels and disturbance of bottom habitat.

Volumes of runoff would be increased because of clearing and paving of the site. Runoff could be contaminated by spills or leaks of chemicals, petroleum products, or other hazardous material. Diking and containment of areas where hazardous materials are stored and handled, with adequate collection, treatment and disposal facilities can reduce the danger of contamination of ground or surface waters.

Air emissions would result from the storage and transfer of petroleum, and operation of vessels, vehicles and equipment. Consideration of emissions in tank design and maintenance of hoses, seals and mechanical equipment can reduce air emissions considerably. Since Fall River is a non-attainment area for Total Suspended Particulates, new sources of air emissions would require an offsetting reduction in emissions from an existing source.

Development of this site for a marine terminal could affect water quality in the Taunton River through occasional oil spills and chronic leakage. As mentioned previously, the Taunton River is classified SB, although it does not currently meet the standards of that classification. Discharges that are not consistent with the designated uses of that classification would require a waiver or change in classification. Use of an offshore pier or mooring would reduce the impacts from a spill or leak since dispersion would be better than along the river banks, but water quality would still be affected. Bilge and ballast water generated by tankers would require treatment and disposal, since they may be polluted with oil, grease and metal shavings.

Noise levels in the area are likely to be increased because of facility construction and operation, and operation of vessels, vehicles and equipment. Noise impacts can be mitigated by the use of noise control and abatement equipment and provision of a buffer zone. The buffer zone will also mitigate the aesthetic impact on adjacent areas.

Dredging and construction of berthing facilities will result in increased turbidity and displacement of bottom habitat. Disposal methods and sites will be a major concern. Use of an offshore mooring or pier will minimize dredging requirements, but maintenance dredging spoils will require disposal in carefully selected and designed sites, since they may be polluted or contaminated. This site is upriver of the maintained channel but depths in the river are approximately 25 to 35 feet at this point.

This site is not designated as a port area by the Massachusetts Coatal Zone Management (CZM) Program, so onshore and underwater construction would be presumed to involve significant impacts. The significance of those impacts would be determined by relevant local, state and federal standards. The permitting process for use of this site as a pipeline landfall or marine terminal/tank farm would involve federal and state agencies, as well as the City of Fall River. Dredging would require a permit from the U.S. Army Corps of Engineers and the Environmental Protection Agency (EPA) and a Water Quality Certificate from the Massachusetts Division of Water Pollution Control.

Construction of berthing facilities or a pipeline would require a Tidelands License from the Massachusetts Division of Waterways and a permit from the Corps. Discharge or pollutants into the air or water would be subject to review by the EPA and the Massachusetts Divisions of Air Quality Control and Water Pollution Control. Onshore disposal of solid wastes, hazardous or contaminated material, or dredge spoil would require approval from the Massachusetts Department of Environmental Quality Engineering and the EPA. Increased noise levels would be subject to local, state and federal regulations. Ocean disposal of dredge spoil would require approval of the Corps and EPA. Transfer of fuel between tankers and shore tanks would require the approval of the U.S. Coast Guard, while use of this site as a pipeline landfall would require the approval of the Federal Energy Regulatory Commission and construction of a pipeline to connect to existing transmission lines would require the approval of the Massachusetts Department of Public Utilities. If the pipeline is used in interstate transport of gas, the U.S. Interstate Commerce Commission would be involved. Since this site would be a coastal energy facility, approval would be required from the Massachusetts Energy Facilities Siting Council. State permits and licenses are involved, so an Environmental Notification Form would be required. Federal permits are required, so development would be subject to review by the Massachusetts CZM Office for consistency with the state CZM Program Policies.

Permitting should be closely coordinated to insure that necessary mitigation measures are implemented.

The development potential of these sites does not appear favorable. Requirements associated with development of this site could have significant impacts, most of which could be mitigated providing adequate consideration is given during design and operation.

Sites F and G are shown on Figure 24. Site F is the location of Hancock Marine, while site G is currently occupied by a lumber yard and a veterinarian's office. Development of site G for OCS support/coastal energy activities is dependent on the development of site F or other nearby waterfront sites. Site F consists of approximately eight acres and site G consists of approximately three acres.

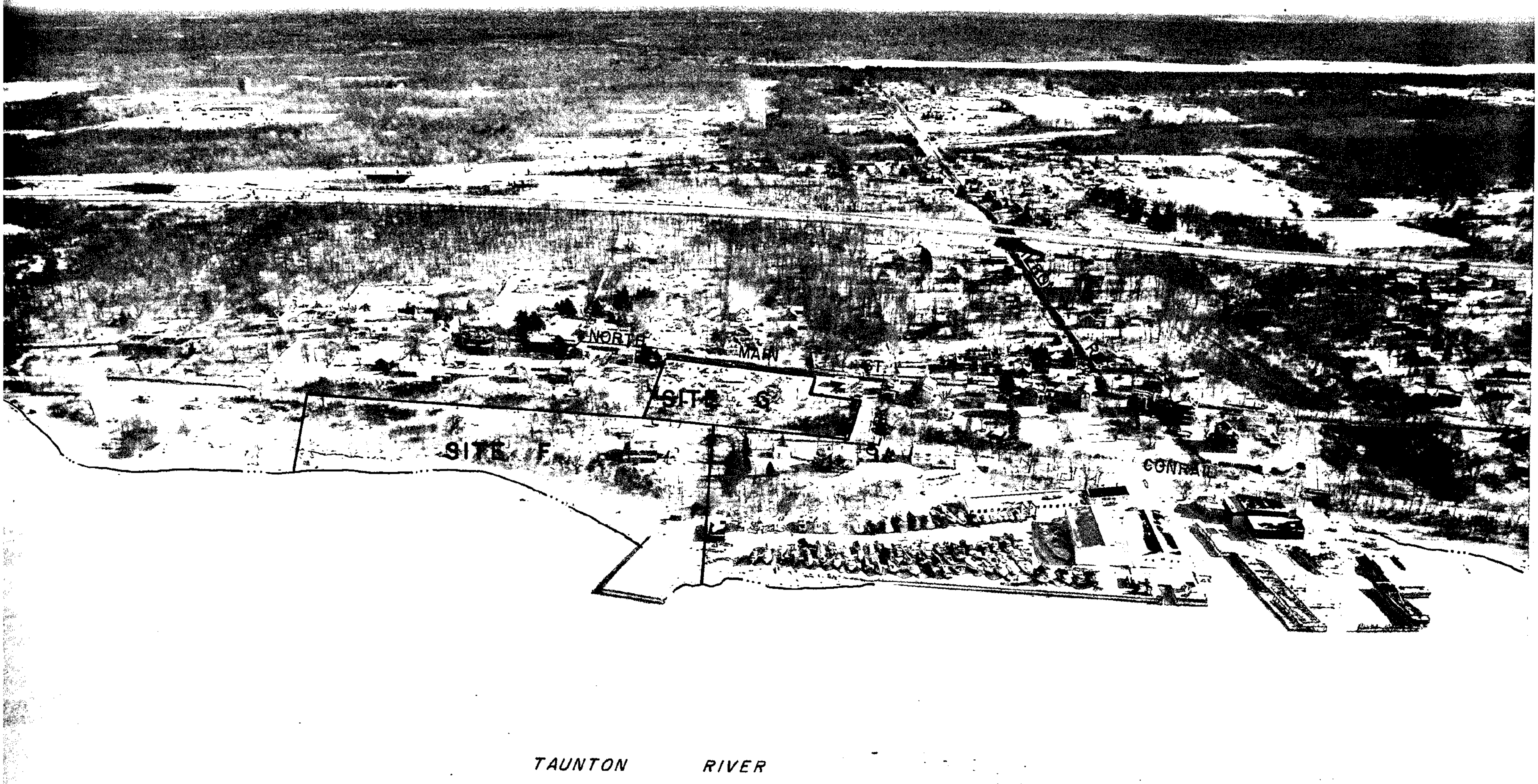


FIGURE 24

The most likely potential use of site F is as an informal transfer point, serving ancillary industries in the area. Supply boats from service bases elsewhere in Fall River, Davisville, or other Narragansett Bay ports would use the berthing facilities to transfer equipment or personnel from these ancillary industries to offshore operations. The site is too small to serve as a service base, but the existence of a pier reduces the amount of capital investment necessary for development. With some maintenance dredging along the face of the pier to provide depths of at least 15 feet, it appears that the existing pier could provide approximately 350 feet of berthing space. Although this site is north of the turning basin and the federally-maintained channel in the Taunton River, depths in the main channel of the River at this point are approximately 25 to 30 feet, less than 20 yards offshore. Land access to the site is poor, however, and improvement would be difficult and expensive, so that use of this site for a mud or cement facility, or pipeline/platform installation support base appears unlikely. Hancock Marine currently provides marine-oriented machine shop and fabrication services, including some work for the OCS industry. It appears that development of this site as a transfer point, in connection with an increase in the OCS-related activity of Hancock Marine or the establishment nearby of ancillary industries (including tool and equipment companies, logging/ perforating companies, completion/ production companies, and inspection/ testing companies - some perhaps located at site G) could occur.

Development of this site would involve dredging berths and an access way to the channel to a depth of at least 15 feet; clearing and grading of the pier and some adjacent land; rehabilitation of the pier, including installation of a fender system and mooring devices; and improvement of access to the pier.

Impacts of development and operation of this site would include increased and polluted runoff; increased land and water traffic in the area; and temporary turbidity and disturbance of bottom habitat during dredging. Dredge spoils could affect local air and water quality unless disposed of in a satisfactory manner.

This site is not designated as a port area by the Massachusetts Coastal Zone Management (CZM) Program, so development would be presumed to involve significant impacts. The significance of those impacts would be determined by relevant local, state and federal standards. The primary development requirement of this site is maintenance dredging and the permitting process would involve the U.S. Environmental Protection Agency (EPA), the Army Corps of Engineers and Massachusetts Division of Water Pollution Control. Approval for discharge of pollutants into the air and water would be required from the EPA and the Divisions of Air Quality Control and Water Pollution Control. Use as an OCS support facility would require the approval of the Massachusetts Energy Facilities Siting Council. Since a state permit is involved, an Environmental Notification Form would be required. Since federal permits are required, development would be subject to review for consistency with Massachusetts CZM Program Policies. Approval of permits should insure that contaminated runoff is not allowed to intrude into ground or surface water; that dredge spoils are contained and disposed of in an acceptable fashion; and that noise levels and aesthetic quality in the area are not impaired during construction or operation.

Sites H and I are located in the northwest corner of Fall River, adjacent to the corporate boundary with Freetown, and are shown in Figure 25. Site H consists of approximately 80 acres and site I consists of approximately 20 acres.

The only potential use of these sites in connection with OCS/ coastal energy activity is as a marine terminal/tank farm, if a refinery is constructed nearby in response to market demand. The site is large enough for most OCS-related uses, but its location several miles up the Taunton River (past the turning basin, the maintained channel and the Brightman Street bascule bridge) and the high cost of development of berthing facilities and site preparation limits its use. It appears that other sites with better location are available for development as service bases, without the dredging requirements of this site. Temporary service bases, pipeline/platform installation support bases, and mud/cement companies are likely to locate on smaller sites with existing berthing facilities.

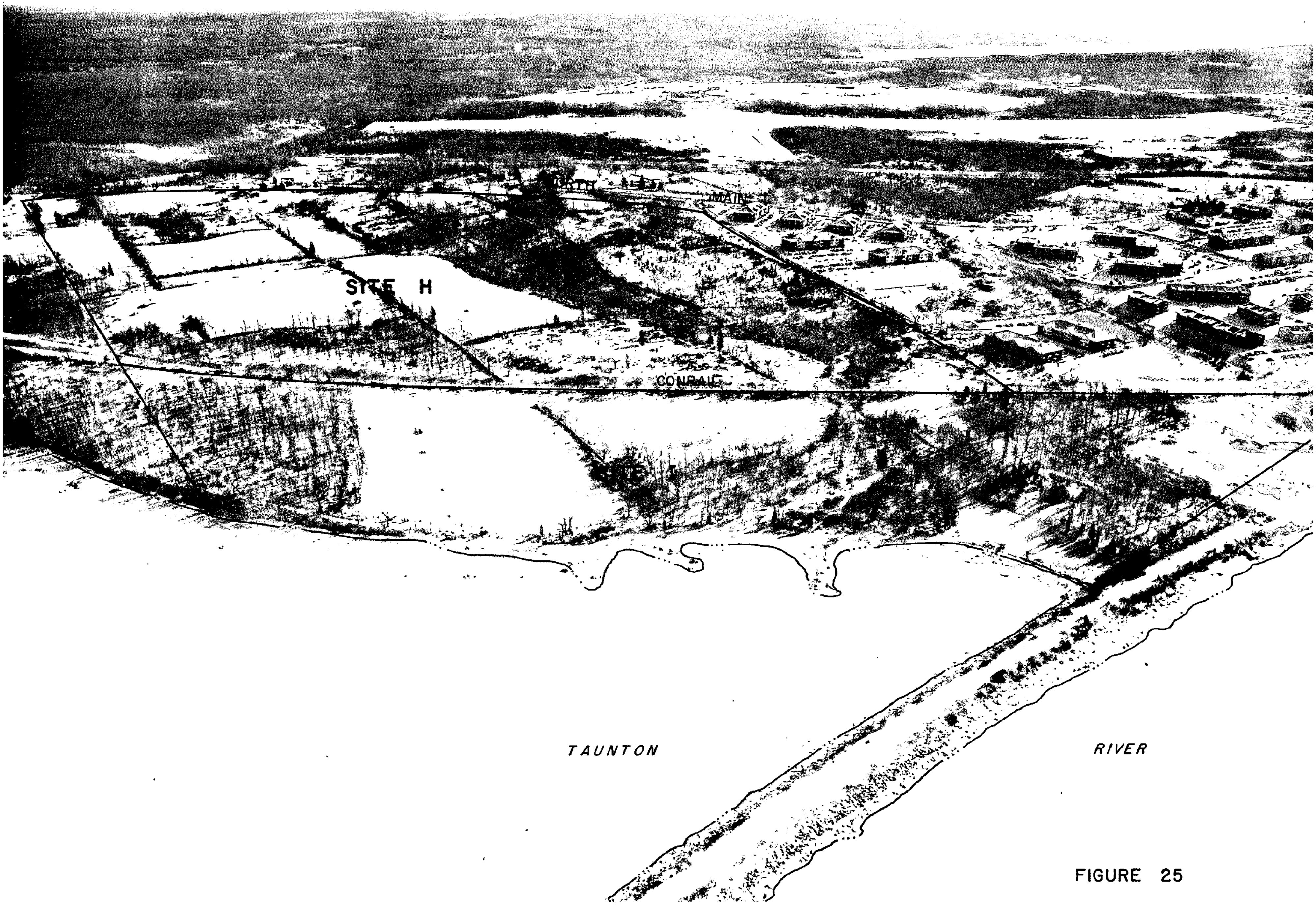


FIGURE 25

If a refinery is constructed in the Fall River area, however, a marine terminal will be necessary. This is the waterfront site closest to the proposed refinery site, and the only large, undeveloped tract of land in the area. Site I has enough land area to accommodate a small (one million barrel capacity) terminal/tank farm, or the two sites could be developed together for a large (four million-plus barrels) facility. Easements for a pipeline to the refinery site would be necessary.

Construction of a marine terminal at this site would require extending the channel approximately two and a half miles. If the current channel depth of 35 feet is maintained, a 20,000 deadweight ton (DWT) vessel would be the largest that could visit the terminal. A refinery processing between 20,000 and 50,000 barrels of crude oil per day would require a 20,000 DWT vessel approximately once every three or four days. Since the Brightman Street Bridge must open to allow passage of tankers, creating severe traffic problems in Fall River and Somerset, increased vessel traffic would create significant problems.

Development of a marine terminal/tank farm on this site would involve: construction and dredging of berths, an approach, and a channel; site clearing and grading; construction of tanks, pumping equipment and pipelines; paving of roads and parking areas; and construction of administration, communication and maintenance facilities. Berths could be provided by means of a sea island pier or floating mooring, as discussed previously.

Impacts would include disturbance of bottom organisms; increased and contaminated runoff; reduced aesthetic quality in the area; increased air emissions; degradation of water quality in the Taunton River; and increased noise levels. Many of these impacts could be minimized by provision of a buffer zone, careful design of facilities and equipment, and good preventive maintenance. Capital investment for this type of facility would be approximately $35 million. Employment from operation of the facility would involve approximately 65 workers, with an annual payroll of approximately $1.3 million.

Dredging and construction of berths would result in temporary increases in turbidity and displacement of natural habitat. The major consideration connected with dredging would be disposal of dredge spoils. Dredging and disposal may require special precautions to prevent contamination of ground and surface water or impacts on local air quality resulting from evaporation.

Site clearing, grading and paving is likely to result in increased volumes and contamination of runoff. Areas where hazardous materials are stored or handled should be diked, and the runoff collected for treatment and disposal. A drainage plan to control and collect the flow of runoff from the site should be developed.

Development of this site for a marine terminal could affect water quality in the Taunton River through occasional oil spills and chronic leakage. Use of an offshore pier or mooring would reduce the impacts from such a spill or leak since dispersion would be better than along the river banks. Bilge and ballast water generated by tankers will require treatment and disposal, since they may be polluted with oil, grease and metal shavings.

Air emissions would result from the storage and handling of petroleum, and operation of vessels, vehicles and equipment. Consideration of this problem in tank design and maintenance of hoses, seals and mechanical equipment can reduce air emissions considerably. Since Fall River is a non-attainment area for Total Suspended Particulated, introduction of a new source of air emissions would require an offsetting reduction in emissions from an existing source.

This site is not designated as a port area by the Massachusetts Coastal Zone Management Program, so development is presumed to involve significant impacts. Development of this site as a marine terminal/tank farm would require approval from the Massachusetts Energy Facilities Siting Council.

Dredging and filling would require a permit from the U.S. Army Corps of Engineers and the Environmental Protection Agency (EPA) and a Water Quality Certificate from the Massachusetts Division of Water Pollution Control. Construction beneath the water would require a permit fron the Corps and a Tidelands License from the Massachusetts Division of Waterways. Ocean disposal of dredge spoil would require approval from the Corps and EPA, while onshore disposal would require approval from the Corps and the Massachusetts Department of Environmental Quality Engineering. Transfer of fuel between tankers and storage tanks would require approval of the U.S. Coast Guard.

Discharge of pollutants into the air or water would require the approval of the EPA and the Divisions of Air Quality Control and Water Pollution Control. Disposal of solid waste and hazardous or contaminated materials would be subject to local, state and federal regulations. Increased noise levels would also be subject to local, state and federal regulations. Since state permits and licenses are involved, an Environmental Notification Form would have to be filed with the state. Since federal permits are involved, development would be subject to review by the Massachusetts Coastal Zone Management Program.

APPENDIX A

DEVELOPMENT OF ESTIMATES OF OFFSHORE OPERATIONS

Prediction of offshore development scenarios is necessarily an imprecise process, since the primary information required, size and location of economically recoverable resources, is unknown. Resources quantities can only be roughly estimated and are revised frequently. The Environmental Impact Statements for Lease Sales 40 and 49 contained conditional, mean statistical estimates of 1.8 and .152 billion barrels of oil respectively, for example, but later studies identified conditional, mean statistical estimates for areas leased under both sales as .029 billion barrels of oil. The continually changing nature of resource estimates indicate that they cannot be considered any more than well-educated guesses.

This appendix presents the assumptions and methodology used to generate the offshore development scenarios used in determining the onshore support requirements contained in Chapter IV. Resource estimates are discussed first, followed by exploration, development, and production levels and schedules.

A. Resource Estimates

The existence of oil and/or gas can be confirmed only by physical evidence produced by drilling. In the early phase of activity before exploratory drilling has been conducted, estimates are made by identifying areas of resource potential on the basis of available information and geologic knowledge and theory. As exploration proceeds, these estimates are revised based on the results of exploratory activity.

Resource estimates are prepared by the US Geological Survey (USGS) using the best available information and techniques. There are two types of estimates, conditional and risked. Conditional estimates assume that recoverable hydrocarbons will be discovered, and assign a statistical probability to various quantities of resources. Generally, conditional estimates are given for the fifth and ninety-fifth percentile of probability, and the statistical mean. The five precent estimate indicates a five percent probability that recoverable resources will be less than the corresponding quantity, while the ninety-five percent estimate indicates a ninety-five percent probability that resources will be less than the corresponding quantity. Risked estimates offer a single quantity, which allows for the possibility that no recoverable hydrocarbons will be discovered, and are somewhat lower than the conditional mean estimate.

In 1975, USGS conditional estimates of recoverable resources in the Mid-Atlantic OCS Region were:

	5%	Mean	95%
Oil (billions of barrels)	0	1.8	4.6
Gas (trillions of cubic feet)	0	5.3	14.2

Conditional estimates of resources contained in lease area 40, as of 1977, ranged from 0.4 to 2.6 billion barrels (bbls) of oil and 2.6 to 12.8 trillion cubic feet (cf) of gas. Conditional estimates of resources contained in lease area 49, as of 1978, were:

	5%	Mean	95%
Oil (billions of barrels)	.028	.152	.320
Gas (trillions of cubic feet)	.46	2.53	5.33

As of 1980, however, conditional mean estimates of the areas included in both Sales 40 and 49 had been reduced to .029 billion bbls of oil and 3.08 trillion cf of gas. It had also been predicted that these sales would produce no economically recoverable hydrocarbons. Current risked estimates for the Mid-Atlantic OCS Region, as of June 1980, are .530 billion bbls of oil and 4.11 trillion cf of gas. These estimates have been used in this study, and no effort has been made to resolve discrepancies with previous regional or tract-specific figures.

With regard to the North Atlantic OCS Region, 1975 USGS conditional estimates of recoverable resources were:

	5%	Mean	95%
Oil (billions of barrels)	0	0.9	2.4
Gas (trillions of cubic feet)	0	4.2	12.5

Conditional estimates of resources contained in the area covered by Lease Sale 42, as of 1977, ranged from .18 to .65 billion bbls of oil and 1.2 to 4.3 trillion cf of gas. These were later revised to .53 billion bbls of oil and 3.5 trillion cf of gas. Current risked estimates for the entire North Atlantic Region, as of December, 1980, are .356 billion bbls of oil and 1.78 trillion cf of gas. These estimates have been used in this study, and no effort has been made to resolve discrepancies with previous regional or tract-specific figures.

As can be seen, resource estimates are no better than well-educated guesses and can vary considerably depending on the purpose of the estimate and the information available. For the purposes of this study, current risked estimates have been used. New estimates are presently being prepared by the USGS for release in the spring. These estimates may differ from those used here and could modify the conclusions of this study. The estimates used here are the best available at this time, however.

B. <u>Offshore Development Estimates</u>

There are several methodologies available for estimating offshore development scenarios and onshore facility requirements. The principal methodologies were developed by the New England River Basins Commission, the Conservation Foundation, and Roy F. Weston, Inc. In this study, the New England River Basins Commission (NERBC) methodology was the primary methodology utilized, although it was not strictly adhered to in all cases.

Very little information is available on the North Atlantic Region, due to the lack of previous activity, and the complex nature of offshore and onshore areas in the region makes projection of information developed in other regions difficult. In addition, the Narragansett Bay area is likely to be affected by activity in both the North and Mid-Atlantic Regions, as well as Canada. The following analysis is based on the best available information and assumptions presented herein.

The principal information necessary for development of onshore requirements and impacts are schedules and levels of production, and the number of platforms installed. These have been estimated separately for the North and Mid-Atlantic Regions.

For the Mid-Atlantic, resource estimates of .530 billion bbls of oil and 4.11 trillion cf of gas have been used. Assuming a ratio of 1,000 cf of associated gas to 1 bbl of oil, .53 trillion cf of gas will be associated with oil, and 3.58 trillion cf of gas will be free or non-associated. In order to work with the resource estimates more easily, all resources have been converted to barrel of oil equivalents (BOE). Oil resource estimates have been converted directly, while gas resources have been converted on the basis of 10,000 cf of gas per BOE, resulting in 411 million BOE of gas. Total resources, therefore, are 941 million BOE.

Based on the potential depths of finds (assumed to be from 350 to 600 feet) and distance from shore (assumed to be from 65 to 90 miles offshore), 50 million BOE has been used as the minimum economic field size for Mid-Atlantic resources. Using the NERBC methodology, eight economically recoverable fields will be discovered, with the largest field containing approximately 190 million BOE. Other fields will contain approximately 180 million, 140 million, 120 million, 100, million, 60 million, and 50 million BOE, respectively. The maximum unassociated gas field has been assumed to contain approximately 140 million BOE, or 1.4 trillion cf of gas. Other free gas fields will contain approximately 120 million BOE and 100 million BOE, respectively.

For associated gas, it has been assumed that approximately 1,000 cf of gas will be discovered with each barrel of oil. One hundred million barrels of oil would have 100 billion cf of gas associated with it, therefore, for a total of 110 million BOE. The ratio of gas to total find would be:

$$\frac{\text{10 million BOE gas}}{\text{110 million BOE in field}} = .091$$

For the oil and associated gas finds described above, the relative quantities of oil and gas would be approximately:

190 million BOE x .091 = 17.3 million BOE gas
190 million - 17.3 million = 172.7 million BOE oil

180 million BOE x .091 = 16.4 million BOE gas
180 million - 16.4 million = 163.6 million BOE oil

100 million BOE x .091 = 9.1 million BOE gas
100 million - 9.1 million = 90.9 million BOE oil

60 million BOE x .091 = 5.5 million BOE gas
60 million - 5.5 million = 54.5 million BOE oil

50 million BOE x .091 = 4.5 million BOE gas
50 million - 4.5 million = 45.5 million BOE oil

Rounding off fractions, it has been assumed that the following finds will occur:

	.173	billion bbls oil, .17 trillion cf associated gas
	.164	billion bbls oil, .16 trillion cf associated gas
	1.4	trillion cf non-associated gas
	1.18	trillion cf non-associated gas
	1.0	trillion cf non-associated gas
	.091	billion bbls oil, .09 trillion cf associated gas
	.057	billion bbls oil, .06 trillion cf associated gas
	.045	billion bbls oil, .05 trillion cf associated gas
Totals:	.53	billion bbls oil
	3.58	trillion cf non-associated gas
	.53	trillion cf associated gas
	4.11	trillion cf gas

Based on the latest USGS estimates of recoverable hydrocarbons in areas covered by Lease Sales 40 and 49, it has been assumed that no commercially exploitable finds will occur as a result of those sales. The present schedule of future lease sales in the Mid-Atlantic is:

Sale No. 59 - December, 1981
Sale No. 76 - November, 1983

It has been assumed that exploratory rigs will be available in 1982, when permits required for drilling in the tracts leased under Sale 59 have been obtained, and the first find will occur during 1983 in tracts leased under that sale. It has also been assumed that the permitting process for drilling in lease area 76 will require approximately one year, with the first find in that area occurring during 1985. In order to develop a schedule of requirements and impacts due to offshore operations, the following scenario has been assumed:

Find A	1983	.091 billion bbls oil, .09 trillion cf gas
Find B	1984	1.4 trillion cf gas
Find C	1984	.045 billion bbls oil, .05 trillion cf gas
Find D	1985	1.18 trillion cf gas
Find E	1985	.173 billion bbls oil, .17 trillion cf gas
Find F	1985	.164 billion bbls oil, .16 trillion cf gas
Find G	1986	.057 billion bbls oil, .17 trillion cf gas
Find H	1987	1.0 trillion cf gas

This scenario is highly speculative, but provides a reasonable framework through which to identify the timing of future activities.

In order to determine the number of exploratory rigs required, it has been assumed that 253 tracts will be offered under Sale 59, and 40%, or 101, will be leased. Sale 76 will offer 170 tracts, with 25%, or 43 leased. Two wells will be drilled per leased tract, for a total of:

2 wells/tract x 101 leased tracts =	202 wells
2 wells/tract x 43 leased tracts =	86 wells
	288 wells

Assuming that exploration will begin in 1982 and proceed through 1990 (three years after the last find), with each rig drilling four wells per year, 72 rig-years (288 wells ÷ 4 wells/rig/year) will be required over an eight-year period, for an average of nine rigs operating each year. At the peak of exploratory activity, in 1986, 12 rigs will be in operation.

In order to determine the number of platforms required, it has been assumed that 24 wells will be drilled from each platform (two rigs per platform drilling four wells per year over a three-year period) of which 85%, or 20, will be productive. A 20-year life for oil-gas wells and a 15-year life for free gas wells, and the following production rates have been assumed:

oil-gas wells:	8,767 bbls of oil/platform/day 8,767,000 cf of gas/platform/day
gas wells:	145,638,000 cf of gas/platform/day

In reality, the quantities of hydrocarbons produced from a well decrease after peak production has been reached. However, by alternating production wells on a platform, conducting remedial work, such as workover, on a platform when production decreases significantly, and use of state-of-the-art extraction technologies, it has been anticipated that platforms can maintain these levels of production over the life of a field. The number of platforms required for each find is as follows:

Find A, 1983: $$\frac{.091 \text{ billion bbls of oil}}{8{,}767 \text{ bbls of oil/platform/day} \times 365 \text{ days/yr} \times 20 \text{ yrs}}$$

$$= \frac{.091 \text{ billion}}{63{,}999{,}100} = 1.4$$

Say 2 platforms

Find B, 1984: $$\frac{1.4 \text{ trillion cf of gas}}{145{,}638{,}000 \text{ cf of gas/platform/day} \times 365 \text{ days/yr} \times 20 \text{ yrs}}$$

$$= \frac{1.4 \text{ trillion}}{1{,}063{,}157{,}400{,}000} = 1.4$$

Say 2 platforms

Find C, 1984:	$\frac{.045 \text{ billion bbls of oil}}{63,999,100}$	= .7 Say 1 platform
Find D, 1985:	$\frac{1.18 \text{ trillion cf of gas}}{1,063,157,400,000}$	= 1.2 Say 1 platform
Find E, 1985:	$\frac{.173 \text{ billion bbls of oil}}{63,999,100}$	= 2.7 Say 3 platforms
Find F, 1985:	$\frac{.164 \text{ billion bbls of oil}}{63,999,100}$	= 2.5 Say 3 platforms
Find G, 1986	$\frac{.057 \text{ billion bbls of oil}}{63,999,100}$	= .9 Say 1 platform
Find H, 1987:	$\frac{1.0 \text{ trillion cf of gas}}{1,063,157,400,000}$	= .9 Say 1 platform

This results in a total of 14 production platforms. In addition, collection/metering/pumping stations would be required. Design, construction, transportation, and installation of platforms can take up to three years, but for the purposes of this study, it has been assumed that the process would require only two years, due to a current surplus of platforms and platform construction capacity. It has also been assumed that no production will occur from a platform until development activities on that platform are completed, and that each rig (two rigs per platform) can drill four wells per year. Since 24 wells will be drilled from each platform, development will require three years (24 wells drilled per platform ÷ 2 rigs per platform with 4 wells per rig per years).

The same process has been conducted for the North Atlantic OCS Region, with some variation in assumptions. Resource estimates of .356 billion bbls of oil and 1.78 trillion cf of gas have been used. The same ratio of associated gas to oil (1,000 cf of gas/1 bbl of oil) and the same factor for converting gas to barrel of oil equivalents (10,000 cf of gas/1 BOE) have been used for the North Atlantic Region as were used for the Mid-Atlantic. As a result, it has been assumed that .356 trillion cf of associated gas (.356 billion bbls of oil x 1,000 cf of gas/bbl of oil) and 1,424 trillion cf of non-associated gas (1.78 trillion cf of gas - .356 trillion cf of associated gas) will be discovered. Total resources in the region, therefore, are estimated at 534 million BOE [.356 billion bbls of oil + .178 billion BOE of gas (1.78 trillion cf of gas ÷ 10,000 cf of gas/BOE)].

Based on the assumed depth of finds (200 to 600 feet), distance offshore (110 - 150 miles), and the often harsh weather conditions in the area, 80 million BOE has been assumed to be the minimum-sized economically recoverable field.

Using the NERBC methodology, four economically recoverable fields will be discovered, with the largest field containing approximately 210 million BOE. Other fields will contain approximately 142 million, 102 million, and 80 million BOE, respectively. The maximum non-associated gas field has been assumed to be 1.4 trillion cf, or 140 million BOE. Since the total non-associated gas estimate for the region is 1.424 trillion cf, only one free gas field will occur. For associated gas, the same oil-to-gas ratio used in the Mid Atlantic Region (.091) has been used, so relative quantities of oil and associated gas in the three oil-gas fields would be approximately:

210 million BOE x .091 = 19.1 million BOE gas
210 million - 19.1 million = 190.9 million BOE oil

102 million BOE x .091 = 9.3 million BOE gas
102 million - 9.3 million = 92.7 million BOE oil

80 million BOE x .091 = 7.3 million BOE gas
80 million - 7.3 million = 72.7 million BOE oil

Rounding off fractions, it has been assumed that the following finds will occur:

.190 billion bbls oil, .19 trillion cf associated gas
1.42 trillion cf non-associated gas
.093 billion bbls oil, .09 trillion cf associated gas
.073 billion bbls oil, .08 trillion cf associated gas

Totals:	.356	billion bbls oil
	1.42	trillion cf non-associated gas
	.36	trillion cf associated gas
	1.78	trillion cf gas

Sale 42 occurred in December, 1979, but no exploratory drilling has taken place up to this time. Exploratory drilling is expected to begin in 1981. Two additional sales are scheduled - Lease Sale 52 scheduled for October, 1982, and Lease Sale 82, scheduled for October, 1984. It has been assumed that approximately one year will be required to obtain drilling permits after each of these sales. Sale 42 offered 116 tracts and 63 were leased; it has been assumed that 85 tracts will be offered in Sale 52 and 70 tracts will be offered in Sale 82, with 40% and 25% leased, respectively. This results in 34 tracts leased under Sale 52 and 18 tracts leased under Sale 82. Assuming that two wells are drilled per leased tract, there will be a total of 230 wells drilled, as follows:

2 wells/tract x 63 leased tracts	=	126 wells
2 wells/tract x 34 leased tracts	=	68 wells
2 wells/tract x 18 leased tracts	=	36 wells
		230 wells

Assuming that a rig drills four wells per year and that exploration continues over an eight-year period, an average of seven rigs will be required (230 wells ÷ 4 wells/year = 57.5 rig-years ÷ 8 years = 7 rigs). A peak of 10 rigs is anticipated.

Based on the assumed finds and the lease schedules presented above, the following scenario has been developed:

Find A, 1983:	.093 billion bbls oil, .09 trillion cf associated gas
Find B, 1984:	.19 billion bbls oil, .19 trillion cf associated gas
Find C, 1985:	1.42 trillion cf non-associated gas
Find D, 1986:	.073 billion bbls oil, .08 trillion cf associated gas

This scenario is highly speculative, but provides a reasonable framework through which to identify the timing of future activities.

Assumptions regarding platform requirements remain the same as for the Mid-Atlantic Region:

- two development rigs will be used per platform;
- each rig will drill four wells per year for three years;
- 85% of the wells will be productive;
- life of an oil-gas well is estimated at 20 years with 15 years for a gas well;
- production of 8,767 bbls of oil/platform/day for oil-gas fields and 145,638,000 cf of gas/platform/day can be sustained over the life of the field.

Based on these assumptions, the number of platforms required will be:

Find A, 1983: $\dfrac{.093 \text{ billion bbls of oil}}{63{,}999{,}100} = 1.5$ Say 2 platforms

Find B, 1984: $\dfrac{.19 \text{ billion bbls of oil}}{63{,}999{,}100} = 2.9$ Say 3 platforms

Find C, 1985: $\dfrac{1.42 \text{ trillion cf of gas}}{1{,}063{,}157{,}400{,}000} = 1.4$ Say 2 platforms

Find D, 1986: $\dfrac{.073 \text{ billion bbls of oil}}{63{,}999{,}100} = 1.1$ Say 1 platform

This results in a total of 8 production platforms. In addition, collection/metering/pumping stations would be required. Design, construction, transport, and installation has been assumed to take three years. An estimate of two years was used for the Mid-Atlantic Region, but three years appears more reasonable here, due to the harsher environmental conditions, greater distance offshore, and the fact that surplus platforms and construction capacity would be reduced by satisfying the demands of the potentially richer Mid-Atlantic fields. No production will occur on a platform until development is completed, which is expected to take three years.

APPENDIX B

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